7-2500-5291-2
E-002/GR-91-1

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company (NSP) for Authority to Increase Its Rates for Electric Service in the State of Minnesota	FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION--PART I--(REVENUE REQUIREMENTS)

The above-entitled matter came on for evidentiary hearing before Administrative Law Judge Richard C. Luis at the Large Hearing Room of the Public Utilities Commission, 780 American Center Building, St. Paul, Minnesota on June 19-21, June 24-28, July 1-3 and July 8-10, 1991. The record in this matter closed on September 17, 1991.

Public hearings for the purpose of receiving the comments and questions of affected ratepayers were held as follows (approximate attendance): May 22 -- Montevideo (19); May 23 -- St. Cloud (31); May 28 -- Minneapolis (42); May 29 -- Coon Rapids (20); May 30 -- St. Paul (35); June 5 -- Winona (21); and June 10 -- North Mankato (30). Oral comments were taken at the hearings from 32 witnesses. Northern States Power Company (NSP) and the Minnesota Department of Public Service (DPS) made presentations at each hearing, and appearances were made at four locations by the Office of the Attorney General (OAG). At least one Public Utilities Commissioner attended each hearing except at Winona, due to a conflicting Regional Commissioner's conference. At least one member of the Commission Staff attended each hearing, except at Coon Rapids. Members of the public were allowed to file written comments through August 15, 1991.

Appearances at the evidentiary hearing were as follows: David A. Lawrence and Michael Hanson, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401 and Samuel L. Hanson, Briggs & Morgan, 2400 IDS Center, Minneapolis, Minnesota 55402, on behalf of NSP; Eric Swanson and Julia Anderson, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101, on behalf of the DPS; Dennis Ahlers and Gary Cunningham, Special Assistant Attorneys General, 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101, on behalf of Hubert H. Humphrey, III, Attorney General of Minnesota (OAG); Garrett Stone and Peter Mattheis, Ritts, Brickfield & Kaufman, Watergate 600 Building, Suite 915, Washington, DC 20037-2474, on behalf of North Star Steel (North Star); Byron E. Starns and James J. Bertrand, Leonard, Street and Deinard, 150 South Fifth Street, Suite 2300, Minneapolis, Minnesota 55402, on behalf of Minnesota Energy Consumers (MEC); Peggy Wells Dobbins, 915 Aduana Avenue, Coral Gables, Florida 33146, on behalf of Champion International (Champion); Thomas J. Weyandt, Assistant City Attorney, 647 City Hall, St. Paul, Minnesota 55102, on behalf of the City of St. Paul, and the Board of Water Commissioners of the City of St. Paul; Elmer Scott, 171 Iris Park Place, 1885 University Avenue West, St. Paul, Minnesota 55104, on behalf of the Minnesota Senior Federation (Seniors); James W. Ladner, Jr., Robins, Kaplan,

Miller & Ciresi, 1100 International Centre, 900 Second Avenue South, Minneapolis, Minnesota 55402, on behalf of Minnesotans for an Energy Efficient Economy (ME3); Rodney A. Wilson, Wilson Law Office, Suite 500, 701 Fourth Avenue South, Minneapolis, Minnesota 55415, on behalf of Mankato Citizens Concerned with Preserving Environmental Quality (MCCPEQ); William A. Chesnutt, McNees, Wallace & Nurick, 100 Pine Street, P.O. Box 1166, Harrisburg, Pennsylvania 17108-1166, on behalf of Union Carbide Corporation; Frank Pazlar, 405 Sibley Street, Suite 227, St. Paul, Minnesota 55101, on behalf of Minnesota Utility Investors (MUI); John Knapp, Lloyd Grooms and David Cassidy, Winthrop & Weinstine, 3200 World Trade Center, St. Paul, Minnesota 55101, on behalf of Metalcasters of Minnesota (Metalcasters); David C. Roland and Glenn E. Purdue, Messerli & Kramer, 1500 Northland Plaza Building, 3800 West 80th Street, Minneapolis, Minnesota 55431, on behalf of the Suburban Rate Authority; Janet Gonzalez, Betsy Engelking and Bret Eknes, Rate Analysts, and Louis Sickmann, Financial Analyst, on behalf of the Staff of the Minnesota Public Utilities Commission (PUC). Margie Hendriksen, Special Assistant Attorney General, 160 East Kellogg Boulevard, St. Paul, Minnesota 55101, served as Staff counsel.

Notice is hereby given that, pursuant to Minn. Stat. 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 20 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, 160 East Kellogg Boulevard, St. Paul, Minnesota 55101. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. If desired, a reply to exceptions may be filed and served within ten days after the service of the exceptions to which reply is made. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply, and an original and 13 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final Order.

STATEMENT OF ISSUES

Whether Northern States Power Company should be authorized to increase its retail rates for electrical utility service to customers in Minnesota by $98,198,000 and to collect revenues in accordance with the rate design proposed by NSP.

Based upon all the proceedings herein, the Administrative Law Judge makes the following:

FINDINGS OF FACT

JURISDICTION AND PROCEDURAL HISTORY

1. On January 28, 1991, Northern States Power Company ("NSP" or "the Company" or "the Utility") filed a Petition with the Minnesota Public Utilities Commission ("Commission" or "PUC") under Minn. Stat. 216B.16 for an increase in electric rates of $98,198,000 (an 8.1% increase over current rates). The Company also filed a Petition for Interim Rates in the amount of $71,904,000 (a 5.94% increase).

2. On February 12, 1991, the Company made a supplementary filing containing summary schedules showing the rate base, income statement and revenue summary for the first year budget, and bridge schedules summarizing the regulatory adjustments made to the budget in arriving at the test year rate base and income statement.

3. On March 11, 1991, the Commission accepted the Company's filing and suspended the proposed rates until the Commission determines the reasonableness of the proposed rates or the expiration of the ten-month statutory period (whichever comes first) under Minn. Stat. 216B.16, subd. 2.

4. On March 11, 1991, the PUC issued a Notice and Order for Hearing directing that a contested case hearing be convened to determine the reasonableness of the rate changes proposed by NSP.

5. On March 15, 1991, a Prehearing Conference was held before the Administrative Law Judge in the Public Utilities Commission's Large Hearing Room, Seventh Floor, American Center Building, St. Paul, Minnesota. On April 19, 1991, the Administrative Law Judge issued a Prehearing Order establishing the hearing schedule and procedural guidelines governing the conduct of the case and granting Petitions to Intervene to:

1. Hubert H. Humphrey, III, Minnesota Attorney General;
2. Minnesota Utility Investors (MUI);
3. Minnesota Energy Consumers (MEC);
4. North Star Steel (North Star);
5. Metalcasters of Minnesota (Metalcasters);
6. Champion International Corporation (Champion);
7. Union Carbide Corporation;
8. The City of St. Paul and the Board of Water Commissioners of the City of St. Paul;
9. The Suburban Rate Authority;
10. Mankato Citizens Concerned with Preserving Environmental Quality (MCCPEQ);
11. Minnesotans for an Energy Efficient Economy (ME3);
12. Minnesota Senior Federation (Seniors); and
13. The Minnesota Department of Public Service (DPS).

6. On March 22, 1991, the PUC issued an Order setting interim rates in this matter, which Order authorized the Company to collect $71,904,000 in additional annual revenues in the form of a 5.94% surcharge to retail rate schedules as interim rates, beginning with bills for service rendered on and after March 29, 1991. NSP is collecting interim rates subject to refund if

the interim rates are found to be in excess of the final rates determined by the Commission.

7. On May 13, 1991, NSP filed a Motion to Update. That Motion sought to include in the record testimony supporting an additional $5,628,000 in revenue requirements, related to an inadvertently overstated adjustment for advertising expenses and an omitted expense for personal computer depreciation. On May 22, 1991, the DPS filed comments opposing that Motion. After conducting a Motion Conference, the Administrative Law Judge issued an Order on Motion to Update Filing and Certification of Order on June 13, 1991, which Order granted NSP's Motion in its entirety and certified the Judge's Order to the Commission. On June 26, 1991, the Commission issued an Order Affirming Decision of Administrative Law Judge, which Order allows NSP to adjust upward its revenue increase request by $5,628,000, subject to the statutory "cap" holding the Utility to a maximum increase of the amount for which it filed ($98,198,000). See Minn. Stat. 216B.16, subd. 5.

8. In its Rebuttal filing of June 7, 1991, NSP incorporated

the updates later allowed in the Commission's June 26, 1991 Order, made certain other adjustments to its original filing and requested a revised revenue deficiency of $88,704,000.

9. On August 2, 1991, NSP, OAG, MEC and the DPS filed a Stipulation with the Administrative Law Judge regarding Deferred Expenses. This Stipulation lowers NSP's requested revenue deficiency by $3,257,900.

10. On August 20, 1991, NSP filed a Motion for Leave to Reopen the Record to Offer Late Filed Exhibit. This Motion seeks to include evidence reducing NSP's revenue requirements by an additional $1,973,701 due to an overstatement in the Company's Incentive Compensation budget for 1991. For reasons stated below, the Motion is GRANTED. NSP's final requested revenue deficiency is $83,387,000.

SUMMARY OF PUBLIC TESTIMONY AND WRITTEN COMMENTS

11. Thirty-two public commentators spoke or had questions for NSP representatives at the public hearings. The speakers were evenly divided between persons favorably impressed by NSP and generally supportive of a rate increase and persons opposed to various aspects of the Company's request. In Coon Rapids and St. Paul, the only public commentators were persons supportive of the Company. No organized group opposition to the requested rate increase surfaced at the hearings, as most speaking in opposition to the Company were individuals presenting their own concerns.

12. Two persons in Montevideo expressed concern over the Company's having reduced its staff there, with dispatching services having consolidated and moved to St. Cloud. They expressed consternation over having to leave recorded messages instead of dealing with people in initial phone contacts, and were concerned about delayed responses in emergencies that could result from the regional consolidation. The Company is attentive to such concerns and specifically is considering adding back a staff person at Montevideo.

13. The hearing in St. Cloud featured the most opposition to the Company's rate increase request based upon its impact on poor people. Three

individuals and other persons representing social services organizations emphasized that NSP's Central Minnesota service territory is economically depressed with an extremely low wage scale, even for persons who are employed. They argued that many in the area, especially seniors and those on fixed incomes, simply cannot absorb an eight percent rise in electric bills.

14. St. Cloud witness Martha Crow argued that the Company's rates are discriminatory against poor people (specifically women

and people of color, whom she categorized as an identifiable underclass), calling the rate structure regressive and NSP's executive salaries shameful. She urged NSP's executives (including President Edwin Theisen, who was present) to live on the streets and eat in soup kitchens for a time in order to gain an understanding of economic reality.

15. The Minneapolis public hearing included questioning of NSP representatives, particularly Chairman James Howard, on a number of financial and rate design issues in the case. Speakers challenged the appropriateness of ratepayers paying for decommissioning of the Pathfinder nuclear plant in South Dakota, of a monopoly utility being involved in advertising, and of proposing the eventual elimination of the Conservation Rate Break (CRB).

16. Several witnesses in Minneapolis requested rate relief for persons who heat their homes with electric space heating. They argue that since NSP convinced them to buy or build homes designed for electric heat which cannot be retrofitted economically for other types of heat, the Company should now give them significant discounts. They maintain that they have been loyal to the Company over the years, but now feel abandoned because residential electric rates have risen to the point where electric space heating is uneconomical just when they have reached an age when they have to rely on fixed incomes.

17. Leslie Davis, representing Earth Protector, demonstrated at the Minneapolis hearing how photovoltaic cells and windmills convert light and wind energy into electric power. Davis emphasized the importance of society's having to turn away from fossil fuels as sources for electric energy. This should be accomplished by conversion to end uses of electricity requiring less energy and to reliance on renewable energy sources. Unless such actions are taken, diminished air and water quality could make our environment unihabitable due to acid rain, a thinner atmospheric ozone level and global warming. Davis is not concerned that the cost of such conversions might drive up electric rates -- saving the Earth is worth that to him and his group. If action is not taken soon, Davis and his colleagues intend to take their case to the street.

18. Minneapolis witness George Crocker is Executive Director of the North American Water Office (NAWO). Mr. Crocker and his organization take the position that NSP should receive no increase in this case because nothing in its filing deviates from the basic system that rewards the Utility for producing and selling energy. The Company should receive no increase until it adopts a rate structure that emphasizes spending enough money to capture the energy savings available using current technology. Crocker and NAWO estimate that the proposed rate structure in this case captures less than one percent of the potential savings in energy usage. They argue that profits for the Company must be decoupled from sales of electricity. The Company should be spending revenues to provide and install energy-efficient bulbs, appliances,

motors and other hardware for ratepayers, who neither know of the availability of such products nor have the capital to afford their purchase. Crocker supplemented his remarks with a letter filed prior to August 15.

19. Remarks from public witnesses in Coon Rapids and St. Paul were all supportive of the Company. NSP was praised for its monetary contribution to Heat Share, a safety net program that last year aided 4492 people from 1544 families in the Minneapolis area. The Company was lauded for its sensitivity to the needs and concerns of poor people by witnesses from the St. Paul Foundation, Metropolitan Senior Federation, Family Service of St. Paul and Capitol Community Services, whose Executive Director highlighted the contributions made by NSP employees who sacrifice their own lunch hours delivering meals to persons confined to their homes. The Company was also praised for sponsoring two careers programs (science and engineering) for Explorer Scouts in the St. Paul area.

20. Witnesses from Economic Development organizations and entities in Montevideo, St. Cloud, Minneapolis and St. Paul were supportive of the Company's economic development efforts, through which NSP provides information and expertise designed to retain and draw new businesses and jobs in the affected areas. These witnesses are grateful for the "partnerships" their organizations have with NSP in such endeavors.

21. An NSP shareholder in Coon Rapids wondered whether last year's total denial of NSP's rate request reflected any hostility on the part of the Public Utilities Commission toward investor-owned utilities, and whether the Commission's action reflects a desire for utilities to be run by government agencies. It was explained to the witness that in the last case the Commission made no rulings on rate-of-return or any other issues, except granting a Motion to Dismiss, and Commissioner Kitlinski and representatives of the DPS and OAG stated that privately-owned and operated utilities should remain that way.

22. Winona witness Karin Sonneman stated that she was opposed to the provision of funds by ratepayers to decommission the Company's Pathfinder nuclear plant at Sioux Falls, South Dakota.

23. Mankato witness Katy Wortel, speaking as an individual (Ms. Wortel was also the witness for MCCPEQ in the evidentiary hearing), advocated either the setting up of a "victims fund", or requiring the Company to invest more heavily in pollution control equipment, as means to address the societal costs (health problems) caused by pollution from electric power plants. Ultimately, the Company must be compelled to rely heavily on renewable energy resources (wind, sun), supplemented by hydro power purchased from western or Canadian utilities. Ms. Wortel advocates a raise in rates, if necessary, to pay for electricity powered by such renewable resources.

24. Most of the letters from individuals commenting on the rate case were against any adjustment of the Conservation Rate Break or against granting a rate increase until the Company begins to commit significant funds toward optimizing cost effective conservation and renewable supply-side technology. Letters supporting an increase were also received, each having the general theme that the Company must be allowed to pay its rising, ongoing expenses and to raise capital.

25. Patricia Werner of Minneapolis wrote in opposition to paying for any costs, direct or indirect, relating to "NSP's acts of misconduct, or other intentional or willful acts". Specifically, she opposes the funding by ratepayers of legal expenses for the "Leo Adams affair", for defending itself in the recent shareholders suit claiming the Company misled investors regarding its last rate filing, and in age, race and sex discrimination suits. She opposes ratepayer subsidies for payment of workers compensation costs related to safety violations, or for damages caused by drug and alcohol abuse and improper safety training. Any clean-up costs, claims, penalties or fines relating to pollution should be paid for by the Company only, as should any verdict amounts attributable to NSP's intentional or negligent acts. Werner maintains further that much of this "mismanagement" has not been disclosed, and that the increase should be denied in its entirety to penalize NSP for that misrepresentation.

26. One party, the Board of Water Commissioners of the City of St. Paul, elected not to file testimony or briefs in the case, and its counsel made only brief appearances at the evidentiary hearing. However, the Commissioners filed a letter supporting NSP's initial proposal for a three-period time-of-day (TOD) rate, which shortens the on-peak period to six (from 12) hours and allows water utilities to better manage their electric usage loads. The Board urges the Commission to limit any post-Order study period for examining three-period TOD rates to six months.

TEST YEAR

27. The appropriate test year for determining NSP's revenue deficiency is the 12-month period from January 1, 1991 to December 31, 1991, as filed by NSP. The use of a forecasted future test year is consistent with NSP's past practice and the Commission's past Orders. NSP's proposed test year is reliable for ratemaking purposes.

28. In addition to its forecasted future test year, NSP filed a historic test year adjusted for known and measurable changes to corroborate the reasonableness of its forecasted future test year. On March 11, 1991, the Public Utilities Commission

accepted the historic test year data into the record as evidence intended to corroborate the 1991 projected test year data.

29. North Star witness J. Bertram Solomon testified that "the Commission could require NSP in the future to move to a true historic test year adjusted for known and measurable changes . . . " (North Star Ex. 89, p. 36). The Administrative Law Judge declines to recommend to the PUC that it issue such an Order. The record fails to establish that historic test years are superior to forecasted test years, which have the virtue of determining costs that are actually necessary and expected during the test year.

BURDEN OF PROOF

30. Minn. Stat. 216B.16, subd. 4 (1990) places on the utility proposing a rate increase the burden of showing the reasonableness of its proposed rates. Under Minn. Stat. 216B.03, every rate made, demanded or received by any public utility ". . . shall be just and reasonable . . . Any doubt as to the reasonableness should be resolved in favor of the consumer."

31. The Minnesota Court of Appeals and Minnesota Supreme Court have addressed the appropriate quantum of proof needed to establish the reasonableness of a proposed rate change. In In re Northern States Power Company, 402 N.W.2d 135 (Minn. App. 1987), the Court of Appeals stated:

> We find . . . that the appropriate quantum of proof needed to establish the reasonableness of a proposed rate change is the same as in any other civil case -- a fair preponderance of the evidence.

On review by the Supreme Court, the determination on burden of proof by the Court of Appeals was affirmed. In re Northern States Power Company, 416 N.W.2d 719 (Minn. 1987). The Court went on to provide further explication of the fair preponderance standard as applied to fact-finding processes in utility rate cases. It noted that the weighing of evidence to be employed by the Commission differs from the weighing of evidence traditionally employed by a court (416 N.W.2d at 722):

> In evaluating the validity of a rate increase application, the Commission should apply the classic burden of proof analysis employed in civil cases in determining whether the utility has established the amount of a claimed cost as a judicial fact. . . . But in the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or shareholders should sustain the burden generated by the claimed cost, the MPUC acts both in a quasi-judicial and a partially

legislative capacity.

32. Intervenors in this case have recommended adjustments which, if adopted, would lower NSP's revenue deficiency. The DPS argues that NSP bears the burden of proving the reasonableness of its position on such issues, and that if NSP has not met that burden, its position must be rejected in each instance. At this stage of the proceeding, the Administrative Law Judge is acting in a quasi-judicial capacity. He interprets the above-noted rulings of the Court of Appeals and Supreme Court to imply that the Judge's fact-finding function in a utility rate case is to determine whether a proponent of a given position has established sufficient facts to support the reasonableness of that position by a fair preponderance of the evidence. The question of whether the evidence thus established on the record results in "just and reasonable" rates is left to the judgment of the Commission.

While it is true that NSP has the burden of proof to establish any change in rates by a preponderance of the evidence, it is likewise true that any party challenging one of NSP's proposals which is supported by substantial evidence must establish its position on the issue with evidence of equal probative value to that of NSP's. Absent such a showing, NSP meets the "preponderance of the evidence" standard on every change it supports with substantial evidence.

CAPITAL STRUCTURE AND RATE OF RETURN

Capital Structure

33. J. Bertram Solomon, testifying on behalf of Intervenor North Star Steel, advocated a common equity ratio of 45%, as opposed to the 47.75% advanced in this proceeding by NSP and accepted by other Intervenors who presented testimony and analysis on rate of return.

34. 47.75% is the actual equity component in NSP's capital structure for 1991. North Star recommends a hypothetical common stock ratio of 45%, the same level as that imputed by the Commission in NSP's 1985 Rate Case, because the Company allegedly has offered no persuasive evidence that the benefits of a common equity ratio in excess of 45% outweigh the costs to the ratepayers of such a ratio. Mr. Solomon points out that ratepayers pay for a high common equity ratio through a higher overall rate of return requirement.

35. Dr. Luther Thompson of the DPS testified that NSP's actual capital structure was reasonable in light of equity ratios of comparable companies. Dr. Matityahu Marcus testified for the OAG that NSP's equity ratio was below the average for other AA-rated utilities (whose average equity ratio is about 48%).

36. Whatever a utility's actual capital structure, the PUC must determine a capital structure that is fair and reasonable for regulatory purposes. If it is unreasonable to conclude that the Company's proposed capital structure is appropriate for regulatory purposes, a different capital structure should be used to determine a company's rate of return. Based upon the equity ratios of comparable companies, the Administrative Law Judge finds that NSP's proposed capital structure for setting rate of return is reasonable.

37. In determining that the Company's proposed equity ratio of 47.75% for the test year was reasonable, Dr. Thompson testified that NSP's approach is a compromise between using the current capital structure and the forecasted capital structure during the regulatory period, which strikes a reasonable balance between investors' and consumers' interests. He then compared NSP's proposed capital structure to the capital structures of companies in two comparable groups, including utilities that provide both gas and electric services, like NSP. The average equity component in that combination group is 48.1%. As pointed out by Dr. Marcus, use of "combination" gas and electric utilities for comparison is reasonable because investors buy stock in NSP as a whole, not just in its electric operations. Thompson's testimony on this issue is evidence of the reasonableness of NSP's proposed capital structure, which balances the competing interests of investors and consumers.

38. In finding a 47.75% equity ratio reasonable, the Administrative Law Judge notes that NSP is not planning the construction of any power plants during the period anticipated to be covered by its proposed rate structure. Such construction is commonly financed by the issuance of long-term bonds (debt capital). An increase in the Company's common equity ratio thus recognizes the financing trends for NSP during the immediate past and the future horizon of rates proposed in this case.

Rate of Return

39. In its January 28, 1991 filing, NSP requested an overall rate of return of 10.35%. The Company based its proposed rate of return on a capital structure consisting of 41.98% long-term debt with a cost of 8.65%, 0.42% short-term debt with a cost rate of 7.78%, 9.85% preferred stock with a cost rate of 6.13% and 47.75% common equity with a cost rate of 12.75%. There were no disputes as to the appropriate costs of debt and preferred stock for determining the overall rate of return.

40. Intervenors DPS, OAG, North Star and MEC filed rate of return testimony in opposition to that filed by Northern States Power Company. The chief dispute between NSP and the Intervenors lies in the contrast between the 12.75% return on equity (ROE)

recommended by NSP and the following ROEs recommended by witnesses for the Intervenors:

Intervenor Witness	Recommended ROE
Thompson - DPS	12.10%
Dahlen - MEC	12.02%
Marcus - OAG	ll.70%
Solomon - North Star	ll.00%

41. Minn. Stat. 216B.16, subd. 6, requires an allowed rate of return that is "fair and reasonable". The Supreme Court of the United States defined the reasonableness of a utility's return in Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923). The Court concluded that a utility did not have rights to profits such as those realized in a speculative venture, but stated that the utility's return:

> ". . . Should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."

In Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the Court reiterated the Bluefield principles and discussed the necessity of properly balancing ratepayer and investor interests in order to fix just and reasonable rates. The Hope Court affirmed the investor requirement for sufficient revenue to cover operating expenses, including services on debt and dividends on stock. By that standard, the investor's return should not only be sufficient to assure confidence in the utility's ability to maintain credit and attract capital, but the return should also be similar to returns on investments in other businesses having corresponding risk.

42. The cost of equity cannot be determined with precision or derived from a formula, but must be derived through the exercise of reasonable judgment after a full review of all evidence and testimony. Northwestern Bell Tel. Co. v. State, 216 N.W.2d 841, 857 (Minn. 1974); Hibbing Taconite Co. v. Minnesota Public Service Commission, 302 N.W.2d 5, 11 (Minn. 1980).

43. The cost of common equity is the return investors require on an investment in the common stock of a company, not what return the company will

probably earn or actually earn. Estimating the cost of common equity requires professional judgment and cannot be done mechanically. This estimating process requires applying acceptable financial valuation methods and taking into account the circumstances of the company, industry and capital market conditions.

44. The cost of common equity for a company whose stock is actively traded is best estimated from available stock market data. The Discounted Cash Flow (DCF) method is a market-oriented opportunity cost approach which views the relationship between the cost of equity, investors' income expectations and market price in a theoretically sound and systematic manner. This method has been relied upon by the Commission in nearly every utility rate case it has considered.

45. The theoretical foundation for the DCF method is that shareholders derive their required return from an investment in two forms: yearly dividend and growth in dividends. The DCF method estimates the cost of common equity by combining an appropriate dividend yield with the future growth rate expected by investors.

46. Since NSP has common equity stock which is actively traded on the New York Stock Exchange, the DCF method of analysis estimating the cost of common equity by combining an appropriate dividend yield with a future growth rate expected by investors is appropriate. Since NSP common equity stock is traded in the market, making its price, dividends and past performance directly observable, primary weight should be given to a direct DCF analysis of NSP.

47. Evidence regarding companies whose risks are comparable should be used as a check on the DCF results for NSP. The PUC adopted that approach in its order in the 1986 NSP rate case. NSP's financial position is strong relative to that of other utilities. Investors distinguish between utilities which are subject to nuclear construction risks and utilities which are not faced with such risks. NSP does not have any nuclear plants under construction.

48. The dividend yield is the dividend rate divided by the stock's price. The major inquiry in the dividend yield analysis is the selection of the appropriate yield period. The selection of the appropriate dividend yield period is one of judgment but should be sufficiently long to average out temporary market aberrations and reasonably reflect the period of time during which the new rates will be in effect.

49. The dividend yield must reflect current conditions as well as investor expectations for the future regulatory period. The growth rate is the rate at which investors expect dividends to grow through their investment time horizon.

50. With regard to the dividend yield, a short term more fully reflects the expectations of investors in the current regulatory period. In an effort to estimate fairly the current dividend yield, DPS witness Dr. Thompson used an average of the two-year annual yield (6.61%), the one-year annual yield (7.09%), the most recent quarterly data (6.82%) and the 20-day yield (6.84%). The resulting average is 6.84%. Dr. Marcus, the OAG witness, used a 12-month period to calculate the dividend yield, which he found

to be 6.9%. Mr.

Solomon, for North Star Steel, determined the current dividend yield of NSP stock to be 6.93%, using a six-month average. Using a one and two-year average, Paul Pender of NSP calculated a 6.39% dividend yield for the Company.

51. The PUC has consistently found a 12-month period to be an appropriate time parameter for determining dividend yield. Northern States Power Company, Docket E-002/GR-87-670 (12 months averaged with three months); Northern States Power Company, Docket Nos. G-002/GR-86-160, G-002/M-86-165; Central Telephone Company, Docket P-405/GR-83-300 (1984) (four quarters). In this case, it is appropriate to give weight to observed yields over a period sufficiently long to adjust for aberrations in the Company's stock price. Observing yield over a one-year period is appropriate for NSP in this matter.

52. Dr. Marcus of the OAG and Paul Pender of NSP argued that financial theory requires that the unadjusted dividend yield figure be adjusted to reflect higher dividends which will be received in the first year. Each adjusted their dividend yield figures by multiplying them by one-half the expected growth rate. In the case of Dr. Marcus, that calculation produced a 7.1% dividend yield figure. Mr. Pender's calculations on behalf of NSP produced a dividend yield figure of 6.61% after multiplying his unadjusted dividend yield (6.39%) by half the growth rate he expected.

53. Company witness Paul Pender does not advocate the use of DCF methodology to determine an appropriate return on equity allowance for NSP in this case. Pender's DCF analysis indicates a 6.61% growth-adjusted yield for NSP and a 6.90% growth factor, for an ROE of 13.51%. For reasons stated below, Mr. Pender and NSP chose not to rely on Pender's DCF analysis as the basis for their recommended level of Return On Equity.

54. The appropriate test year dividend yield for NSP is 7.1%.

55. 7.1% is the (adjusted for first-year growth) yield used by Dr. Marcus in his analysis of NSP for both six-month and one-year prior periods. It is one basis point away from the one-year yield computed by Dr. Thompson (7.09). If Mr. Solomon's derived yield of 6.93% were adjusted up for his anticipated growth in dividends during the first year rates are in effect, the result would be close to 7.1%. A recommended dividend yield of 7.1% is thus reasonable, given the testimony of the three witnesses who performed and relied upon DCF analysis. The Administrative Law Judge finds it appropriate to adjust derived yield upward by half the expected growth rate, as was done by Dr. Marcus and imputed by the Judge to Mr. Solomon's figure. The results match the derived yield for one year of Dr. Thompson, the other witness relying on DCF methodology, so a yield of 7.1% is found to be

reasonable and supported by the record.

56. The most common methods for estimating the growth component using the DCF method are extrapolations from past trends in earnings per share, dividends per share and book value per share, growth in retained earnings and analysts' growth estimates. Since returns on equity and pay-out ratios are not constant, historical growth rates of earnings, dividends and book equity are unequal.

57. Due to the Company's earnings growth between 1980 and 1983, NSP has had a high rate of growth over the last ten years. Its rate of return on common equity increased significantly from 11.7% in 1980 to 17.1% in 1983.

Thereafter, the Company's return on equity declined each year and earnings growth since 1983 has averaged just under two percent per year. In 1986, the PUC agreed that NSP's growth trends should be accorded little weight because of the high growth in the early 1980s. See NSP Dockets 85-108 at 41 and 85-558 at 68.

58. Because of NSP's decreased earnings growth after 1983 and the establishment of a high payout ratio, it is reasonable to presume investors will not rely on long-term growth trends encompassing 1980-85. Although NSP's history of long-term growth is not a valid basis for investor expectation, investors may be expected to take into account dividend growth for the past five years. The 5.62% five-year dividend growth does not, in itself, demonstrate NSP's capacity to maintain such increases in the future but investors should not ignore totally the five-year growth figure because that growth has been maintained while the Company's profitability has dropped.

59. While a short-term period more fully reflects the expectation of investors in the current regulatory period, which is the appropriate period for analyzing prospective dividend yields, the growth-rate component of the DCF method is a longer-run concept. The period selected for the growth estimate should be consistent with an indefinite long-run growth rate for dividends.

60. DPS witness Thompson used an average of five-year and ten-year growth rates along with forecasted rates to determine a reasonable estimate of the growth rate and dividends per share. He used those figures because they are published regularly within the financial community and have been accepted for use among investors. Growth rates beyond ten years are increasingly less important to investors and those less than five years are less reliable statistically due to cyclical highs and lows. Using five and ten-year growth rates strikes a balance between reflecting recent expectations and long-term stability, according to Thompson. Averaging the two growth rates emphasizes a more

recent period, but that period is also the most relevant with respect to investor expectations.

61. Dr. Thompson believes that growth in book value per share tends to be the most reasonable estimate of expected growth and dividends for an indefinite future period, because the historical growth rate and dividends per share may not reflect current market conditions. This is because dividends per share is a function of the dividend payout ratio and earnings per share. When earnings increase or decrease, management commonly adjusts the payout ratio to minimize the impact of earnings fluctuations on dividends. Growth in earnings alone may also be a poor estimate of a utility's expected long-run growth, since earnings can fluctuate widely during the regulatory period because of general economic changes.

62. In calculating the growth component, Thompson examined NSP's five and ten-year growth rates in book value, dividends and earnings per share, as well as log linear growth rates. Thompson determined that a fair and reasonable estimate for the expected growth rate for NSP is in the range of 3.5% to 7.0%. In addition to NSP's historical trends, he based his range on value line estimates and analysts' projections of future growth that indicate that growth and earnings would be lower. He used the midpoint of his range, 5.25%, to estimate expected growth.

63. Based on a current dividend yield of 6.85% (one basis point higher than his mathematically derived yield) and a 5.25% growth rate, Dr. Thompson's estimate of a cost of common equity for NSP is 12.10%.

64. OAG witness Marcus also took into account analysts' forecasts, in particular those of the Institutional Brokers' Estimate System (IBES) and the Zack Survey of Analysts' Forecasts. The IBES forecasts are a compilation of data provided by many of the largest institutional investors and by many brokerage firms. The IBES five-year earnings growth projection for NSP is 3.0%, and Zack's projection is 3.6%. Marcus determined to utilize the 3.3% average of these two as an indicator of analysts' assessments.

65. The growth from retained earnings method projects the growth in book equity attributable to NSP's retention of earnings and is derived by multiplying the Company's prospective rate of return on equity by the proportion of earnings NSP is expected to retain. That methodology produces a growth rate in the range of 4.3 to 4.5% for NSP.

66. Relying on the methods above, Dr. Marcus determined investor growth expectations for NSP to be in the 3.3 to 5.62% range, from which he chose a 4.5% investor expected growth figure for NSP. He chose the 4.5% figure because NSP's fundamental

history does not support the large decline in the analysts' forecasts, and because he believes its growth in dividends (5.62% for the last five years) is suspect, having been sustained by a sharply rising payout ratio.

67. North Star witness Solomon analyzed the historical growth in dividends per share, earnings per share and book value per share for NSP. In noting that dividends grew at an average annual rate of 8.05% between 1981 and 1986, but only at a 5.31% rate from 1986 through 1990, Solomon also observed a continuous reduction in year-to-year growth in dividends between 1984 and 1990. He made observations regarding growth in earnings similar to that of other witnesses relying on DCF methodology (that such growth has waned since 1983). Regarding historical book value per share, Solomon noted two distinct periods of growth -- 1981-1985, when book value grew at an average of 7.55% per year, and 1985-1990, when it grew at an average of only 4.37% per year. His general observation regarding all three indicators is that their rates have significantly declined during the latter part of the ten-year historical period under observation.

68. In arriving at his growth estimate for NSP, Mr. Solomon utilized the average dividends, earnings per share and book value growths he computed (5.46%) and averaged that by a "growth formula" which discounts NSP's growth potential due to low analysts' forecasts and higher-than-normal retention ratios. His "growth formula" figure (4.12%), when averaged with 5.46%, yields 4.79%, which Mr. Solomon used as the upper limit of the investor expected growth rate range for the Company.

69. Mr. Solomon arrived at a lower limit of his final growth range (3.70%) by computing the mid-point of a range of analysts' forecasts. Mr. Solomon's final growth figure under the DCF model is 4.07% (which he did not arrive at directly). He exercised his judgment and chose a point in the lower reaches of an ROE range he determined to be reasonable in order to give additional credence to the growth rates anticipated by publicly-followed financial analysts, to the downward trend in NSP's growth rates in dividends,

earnings per share and book value per share and to the "results of NSP's own financial forecast". North Star Ex. 92, p. 23, line 3.

69. Solomon actually picked an ROE for NSP of 11% from a range of 10.84% to 11.97%. Since his yield recommendation was 6.93%, the Judge has derived this witness's growth figure (4.07%) by subtracting 6.93% from his ROE result.

70. In combining his 6.93% dividend yield with a growth range of 3.70% (analysts' forecasts) to 4.79% (from historical data), Mr. Solomon arrived at a range for ROE from 10.76% to 11.89%. He then made a flotation cost adjustment to recognize that the

Company will be issuing additional common stock in the future, during a period when he assumes that the rates set in this case will be in effect. His flotation cost adjustment (0.8%) when added to his DCF-derived common equity range, yields a range of 10.84% to 11.97%, from which he picked 11.0%.

71. MEC witness Derick Dahlen recommends a 12.02% ROE, which is the Federal Energy Regulatory Commission's (FERC) benchmark rate of return. Dahlen advocates adoption of the FERC benchmark because it satisfies the criteria adopted by the Commission for return on equity. He maintains that FERC establishes its benchmark rate by using a Discounted Cash Flow method, it reflects recent financial markets and is established by a process that is more thorough (includes more companies) than any presented in an individual rate case.

72. MEC argues that the 12.02% rate of return satisfies the PUC's criteria for a fair rate of return in part because NSP has a percentage of common equity high enough to maintain a AA bond rating and therefore is a less risky investment than most of the utilities in the FERC sample. Therefore, if anything, the Company's required return on equity should be lower than the FERC generic rate and MEC's ROE recommendation is generous to the Company.

73. NSP witness Paul Pender estimated his growth component for NSP by averaging historical growth in dividends, earnings and book value per share over the ten-year period from 1979 to 1989. That calculation produces a 6.90% growth figure. If the same calculations are performed for 1980 through 1990, they will produce a growth figure of 6.21%. Pender picked a ten-year period because he believes it encompasses a wide range of economic and financial conditions and is sufficiently long to include both favorable and unfavorable financial performance. NSP Ex. 11, p. 18-19. However, NSP did not rely on its DCF analysis of itself to form the basis of its ROE recommendation.

The rate-of-return witnesses, in order to check the accuracy of their DCF analyses of NSP, performed similar analyses of various groupings of other utilities. Pender calculated a comparable group yield of 7.26% and growth factor of 5.41% for a cost of equity of 12.67% using the DCF method. The rate of return for common equity for Dr. Marcus's comparison group is 11.7%. For "combination" utilities, Dr. Thompson calculated a cost of equity of 11%, and derived a 12.5% return on equity for the electric-only group.

74. The Company maintains that in this case DCF analysis of NSP fails to estimate accurately the cost of equity, and, in fact, significantly underestimates that cost. The Company urges rejection of the DCF model and reliance on a "reality check" involving evidence of allowed returns for NSP under the Risk Premium method, under the Capital Asset Pricing Model (CAPM),

and by examining ROEs allowed other utilities. The Risk Premium method attempts to measure the size of the additional return required for stocks above bond yields to compensate investors for the greater risk of common stock. NSP maintains that it provides a useful check of the accuracy of DCF results as well as an independent measure of the cost of equity. Mr. Pender performed a risk premium analysis for NSP common stock and found that stock returns generally exceed bond yields by about 4.64%. Pender concludes that the cost of equity indicated for NSP under the risk premium method is 14.23%.

75. Mr. Pender performed a CAPM analysis, which divides the risks associated with the stock into systematic risk affecting all companies and unsystematic risk affecting NSP in particular. Systematic risk is measured by regressing rates of return for the individual stock on returns for the stock market index to develop the stock's "Beta". The required return on equity is derived by taking the sum of a risk-free rate and Beta times the difference between the expected market return and the risk-free rate. This analysis depends heavily on the "Beta" figure used. Using the CAPM method, Pender calculated a required return on equity for NSP of 14.07%.

76. Pender also presented evidence showing returns allowed in electric utility rate cases throughout the United States in the past year. The range was 12% to 15.76%, with the average being 12.77%. NSP's most recent decision from the Wisconsin Public Service Commission, issued January 16, 1991 for rates in effect in 1991, allowed an ROE of 12.75%. NSP maintains that it would be unfair and unreasonable for it to be allowed an ROE below returns allowed by other commissions because it must compete with other utilities for capital in the stock and bond markets.

77. Dr. Marcus found the ten-basis-point difference between his DCF calculations for NSP and the comparable group insignificant, so he recommended an ROE of 11.7% (that of the comparable group, as opposed to NSP's 11.6) for the Company.

78. It is appropriate to adopt a growth rate for the test year for Northern States Power Company in this proceeding of 4.8%.

79. The appropriate return on equity for Northern States Power Company during the test year is 11.9% (derived by summing a 7.1% yield component and a 4.8% growth component).

Cost of Capital Summary

80. NSP's appropriate overall cost of capital is 9.94%, compiled as follows:

	Percentage	Cost	Weighted
Average			
Long-term Debt	41.98	8.65	3.63
Short-term Debt	0.42	7.78	0.03
Preferred Equity	9.85	6.13	0.60
Common Equity	47.75	11.90	5.68

Total	l00.00	9.94

Discussion

NSP has not sustained its burden of establishing that its requested return on equity of 12.75% is just and reasonable.

The authorized rate of return must be commensurate with the risks of the enterprise. No purpose is served by allowing a return which is higher than that required by NSP's investors. Authorizing a return in excess of that required by the investors confers windfall gains on the investors, while imposing unnecessary burdens on ratepayers. It is appropriate for the Commission to ensure that the rate of return on equity established for NSP in this proceeding is no greater than the amount necessary to protect investor interests.

The required rate of return is that which is necessary for investors to buy or hold a security. An investor's rate of return should reflect the total evaluation of risks the investor is willing to assume for an expected return on investment. The greater the risk in any investment, the greater must be the expected return to compensate for the risk.

Translating NSP's risk into a just and reasonable return on equity requires an analysis incorporating both NSP's current yield and expected growth, as well as an analysis of companies whose risk is comparable to that of NSP. The DCF method is generally considered the most basic and fair approach for regulatory purposes in determining the cost of common equity.

The Minnesota Public Utilities Commission has consistently utilized the DCF method in making its determinations of the appropriate rates of return for Minnesota utilities. DCF methodology provides objective information concerning the cost of common equity capital during an expected regulatory period.

Using the DCF technique, the cost of equity is derived by calculating the current dividend yield and the expected growth in dividends. The dividend yield must reflect current conditions as well as investor expectations for the future regulatory period. The growth rate is the rate at which investors expect dividends to grow through their investment time horizon.

It is useful to compare companies whose risks for investors are similar to those of NSP's to verify the reasonableness of the results obtained directly for NSP. To confirm their rate of return analyses, Dr. Thompson of the DPS and Dr. Marcus for the OAG performed DCF analyses on comparable groups of utilities. Several criteria were used by these witnesses to establish comparability. For instance, of the 95 electric utilities whose stocks are listed on the New York Stock Exchange, those which are subject to nuclear construction risks were removed from the analysis. NSP has no such risks, and is among the 29 largest companies ranked by revenue size, another classification used to determine a comparison group. It is reasonable to impose a size constraint on the comparison group to make the comparable group manageable, yet statistically meaningful.

The Administrative Law Judge agrees with the Intervenors who argue that the goal of regulation in the rate of return is met when rates are set at the lowest level consistent with allowing the firm the opportunity to earn a return sufficient to meet the above-noted Bluefield and Hope standards. That

conclusion is consistent with Hibbing Taconite Co. v. Minnesota Public Utilities Commission, 302 N.W.2d 5 (Minn. 1980), in which the Supreme Court overturned the Commission's method of focusing on the witness with the lowest return, but not the goal of seeking the lowest sufficient return. The DCF methodology provides an accurate reflection of the risk in purchasing NSP stock.

NSP has requested the Commission, as a "reality check", to compare the rate of return appropriate for the Company under DCF methodology to ROEs granted to other companies in other jurisdictions recently. Such a comparison would be misplaced. No Commission decision has ever based ROE on the findings of other states. Rate of return decisions are unique to the particular company and based upon the capital needs for that company.

Return on equity decisions relied on by NSP are based upon different, older data than will be used in this case. There is no guarantee that the decision reached in those cases would have had the same results regarding ROE in 1990. Other states may have different substantive rules. Investors know the differences in rates may be offset by positive regulatory features, and Minnesota has two such features: interim rates and a forecasted test year.

The risk premium analysis advanced by NSP as part of its "reality check" requires the existence of a mathematical relationship between the stock and bond markets. The results of risk premium methodology are extremely volatile. They can vary based upon the holding period selected. Because of these problems, the PUC has consistently rejected risk premium analysis as a determinant of return on equity.

It is a fair interpretation of NSP's position requesting an ROE of 12.75% that its request is not based on any analysis utilitizing DCF, Risk Premium or Capital Asset Pricing Model, but rather it is based upon NSP's subjective analysis of its own performance.

As for the analyses performed by Mr. Pender for NSP, his DCF analysis for NSP overstates the required ROE due to the proposed growth figure of 6.90%. That figure is overstated because it is the average of ten-year growth rates for earnings, dividends and book value for an inappropriate period of time (1980-89). There is no reason to believe that investors rely upon historical data, such as that relied upon in total by Pender, to the exclusion of analysts' reports and estimates of probable retained earnings. Pender's analysis fails to include shorter, more recent periods, such as the five-year trends, which are available to investors and constitute a portion of the data on which they rely. Had Pender averaged five-year data along with ten-year data using 1980-1990, rather than 1979-1989, the growth figure using Pender's method would have been 4.8%. Had Pender used the more recent ten-year period of 1980-90, his growth figure would have been 6.21%.

Regarding Pender's risk premium analysis, his recommendation of an ROE of 14.23% was calculated using market data for a group of comparable utilities. The components are a 4.64% equity risk premium for such companies which, when added to a 9.59% bond yield, produced a 14.23% result. In past rate cases, the Commission has consistently rejected the use of risk premium methodology for establishing ROE. In the last NSP case where the PUC had the occasion to comment on risk premium methodology, it stated: "The Commission has consistently rejected risk premium methods because of the volatility of

results". Northern States Power Company, Docket Nos. G-002/GR-86-160; G-002/M-86-165 at 50.

The returns utilized by Pender in his risk premium analysis are volatile, ranging from a yearly difference in returns of minus 19.19% to 46.81% only two years later (comparing 1973 to 1975). Such a great degree of variability over a short time span raises serious doubts about the usefulness of the risk premium method.

Risk premium analysis can be developed by taking the "risk free rate", usually treasury bills for the return on long-term government bonds, and adding that to a "risk premium" based on differences in stock returns over bonds for a selected period of time. The subjectivity problem arises in determining which past period to employ in estimating current risk premiums. The risk premium estimate is very sensitive to the period selected, and Pender's application of it is also inconsistent because he mixed a 19-year historical risk premium with the risk-free rate for only the past two years.

Pender calculated a 14.07% estimated cost of equity for NSP using a capital asset pricing model (CAPM). The CAPM utilizes an equity risk premium. Therefore, the same objections to risk premium methodology discussed above apply with equal force to the CAPM methodology.

The CAPM model utilizes Beta as a measure of risk. Beta is a statistical estimate, which is subject to measurement error. Estimated Beta can differ greatly depending on underlying data. The potential varieties of Betas can affect the CAPM result significantly. For instance, had Pender used Standard and Poor's Beta of 0.48 instead of Valu Line's beta of .75, his CAPM estimate would have been over 200 basis points lower than his result of 14.07. Because of such limitations, the CAPM recommendation analysis of Mr. Pender should be rejected.

In his DCF analysis, Pender selected risk-comparable companies for comparison to results at NSP solely on the basis of their bond ratings. Bond ratings alone are not an appropriate measure of risk attributable to common equity, since they reflect investment risks to bondholders, not to common stockholders.

The yield component recommended by the Administrative Law Judge, 7.1%, represents an appropriate judgment based upon the recommendations of expert witnesses who relied upon DCF methodology in calculating an appropriate return on equity for NSP (Thompson, Marcus and Solomon). The yield components recommended by these witnesses ranged from 6.93% (Solomon for North Star) to 7.10% (Marcus for OAG). The 7.1% recommendation for yield matches that of OAG witness Marcus and is very close to that advanced by Dr. Thompson of the DPS. It is noted that when Mr. Solomon's recommended yield of 6.93% is increased by a factor of one-half of his anticipated growth (2.035%), the result (7.07%) approaches the Marcus recommendation of 7.10%. Marcus made his recommendation after adjusting his calculated yield of 6.9% by half of his anticipated growth for the period rates will be in effect. The 7.1% also closely matches Dr. Thompson's calculated one-year annual yield (7.09%). Since the Commission has consistently found a 12-month period to be appropriate in arriving at the yield component, the Administrative Law Judge gave greater weight to Thompson's one-year yield than to the yields for other periods of time which he averaged with the one-year yield.

The estimates made by witnesses relying on DCF analysis constitute deployment of "best evidence" on this issue because they involve investors' actual expectations regarding NSP. This is so because market evidence permits a direct estimate of NSP's cost of common equity. Indirect estimates, based on analyses of comparable companies, should be employed only as a check on the direct estimates.

The growth rate of 4.80% recommended by the Administrative Law Judge strikes a balance between the 5.25% recommended by Dr. Thompson, the 4.60% recommended by Dr. Marcus and the 4.07% recommended by Mr. Solomon. It is noted that Dr. Marcus increased his overall recommendation for ROE by ten basis points to match the ROE he calculated for his comparison group. Imputing those ten basis points to an increase in the growth component results in a growth component of 4.70%. The Administrative Law Judge combined the recommendations of Thompson, Marcus (using 4.70%) and Solomon, giving double weight to those of Thompson and Marcus because he has concluded that the growth component recommended by Mr. Solomon is artificially low.

Solomon's growth recommendation is weighted heavily in favor of analysts' forecasts. As stated by Dr. Marcus, "the magnitude of the future growth decline, based on analysts' surveys, . . . makes no sense when compared with the far lesser decline in analysts' growth estimates for the electric utility industry as a whole". OAG Ex. 92, pp. 22-23. Because of Solomon's over-reliance on analysts' (low) forecasts, and because his application of the Gordon Expected Dividend Formula is viewed by the Judge as driving down the growth factor inappropriately, Solomon's recommendation has been given only half the weight of those of Marcus and Thompson.

Specifically, Thompson's recommendation of 5.25 was factored at 40%, Marcus's of 4.70 at 40%, and Solomon's at 20%. After averaging his Gordon formula result (4.12%) with the average historical growth trends in dividends, earnings per share and book value (5.46%), Solomon used that average of 4.79% as an upper limit of investor expected growth rate range. For his lower limit, he used the mid-point of analysts' forecasts that were discounted by Dr. Marcus. Solomon compounded his tendency toward a low growth component by according extra weight to the low end of his range of possibilities. For these reasons, it is appropriate to give his recommendation less weight.

RATE BASE AND OPERATING EXPENSES

Pathfinder

81. In this proceeding, NSP has requested reimbursement for expenses associated with decommissioning its Pathfinder Atomic Power Plant in Sioux Falls, South Dakota.

82. NSP estimates that the decommissioning of the Pathfinder nuclear plant will cost approximately $12.5 million. Its proposal in this rate case is to include in test year operating expenses $1,675,000 as amortization of decommissioning costs associated with the nuclear portion of Pathfinder during the test year. If NSP is denied recovery from the ratepayers for the decommissioning of the Pathfinder nuclear plant, its net operating income for the purposes of this case will increase by $1,441,000 (reduction in expenses

of $1,888,000 less a reduction in operating revenue of $447,000). The revenue impact of the denial would be $2,421,000.

83. The Administrative Law Judge finds that NSP has failed to prove that its ratepayers should bear the cost of decommissioning the Pathfinder plant.

84. The question of whether or not NSP's proposed cost of $12.5 million to decommission the Pathfinder facility is reasonable is immaterial and need not be reached in this proceeding. The question is whether decommissing costs should be recovered from ratepayers in the test year and future years. It is found that costs associated with the decommissioning are not recoverable from ratepayers because NSP's ratepayers have never received any tangible benefit from the Pathfinder plant. In fact, ratepayers have already paid over $24 million for the nuclear operations at Pathfinder, which operations never produced electric service to NSP's customers.

85. The decommissioning of Pathfinder will offer insufficient guidance for the decommissioning of Monticello or Prairie Island (NSP's other nuclear facilities) to warrant recovery of expenses because the nuclear operation has been inactive for 23 years and any nuclear material remaining there has, at worst, only background levels of radioactivity. Monticello and Prairie Island are likely to have substantially higher levels of radioactivity when they are decommissioned.

86. The OAG argues that recovery of decommissing expenes at Pathfinder in the test year is improper because the facility is not and never was considered "used and useful" within the meaning of Minn. Stat. 216B.16, subd. 6. Although NSP has not attempted to recover decommissing costs through its rate base in this filing, it is found that the Pathfinder nuclear facility is not "used and useful" as required by Minn. Stat. 216B.16.

87. Personnel at the Monticello and Prairie Island plants did not and do not benefit sufficiently from what NSP may have learned at Pathfinder to warrant the recovery NSP seeks in this case. The decisions to build and planning for Monticello and Prairie Island were made before Pathfinder was shut down, the facilities use different technology than Pathfinder did, and Pathfinder could not be used for operations training because of its poor long-term availability. While NSP still has a few employees who participated in the construction, testing and operation of Pathfinder, the record fails to establish sufficiently that their Pathfinder experience had further influence on electric utility operations.

88. The Pathfinder nuclear facility is currently in the decommissioning process. Prior to that, it was in "SAFSTOR", a containment status. The Company maintains that NRC regulations now requiring the eventual total decommissioning of facilities in SAFSTOR were not in force at the time it sought recovery of funds used to construct the plant.

89. NSP maintains that it is saving money by shipping the

nuclear waste from the Pathfinder plant, radiation levels of which are now at or near background levels, as soon as possible. The remaining low-level radioactive waste can currently be shipped to a facility near Richland, Washington, at a significant savings compared to the cost that would be incurred if further delay was required. Because future availability of low-level waste disposal facilities is uncertain, and the costs to ship such waste to one of the newer

facilities are projected to be significantly higher, the Company is proceeding with decommissing at the present time. The Intervenors do not question the prudency of decommissing at this time as compared to in the future. They maintain that NSP should have taken this action two decades ago, at far less cost.

90. NSP maintains that Pathfinder was a highly successful research and development project that allowed it to develop and obtain considerable invaluable insights into the then-emerging technologies associated with nuclear power plants. In addition, the Company argues that Pathfinder provided invaluable training to NSP employees, many of whom still work in the nuclear generation phases of the Company and who have, in turn, provided significant training to newer employees. The record fails to establish those propositions by a preponderance of the evidence.

91. The nuclear reactor facility at the Pathfinder plant never produced electricity for NSP's system. The plant was shut down after an accident in September of 1967, before which time it had only been operating during testing procedures.

92. Subsequent to the accident, NSP settled its dispute regarding Pathfinder with Allis-Chalmers Company, the manufacturer of the failed unit, for $3 million. Intervenors maintain the settlement was for an insufficient amount and that NSP could or should have anticipated the costs of dismantling when it negotiated the settlement. NSP argues that the $3 million settlement was for an appropriate amount and that there is no evidence showing that it could or should have anticipated the costs of dismantling at the time of negotiating the settlement. The Company had originally sought a $10 million recovery from Allis-Chalmers.

93. There is no evidence that NSP received any insurance recovery for its losses at Pathfinder connected with the failure of the nuclear powered unit manufactured by Allis-Chalmers. NSP contends that the issue of whether it should have attempted to recover insurance regarding Pathfinder is irrelevant to this case. It is found that the responsibility for insuring Pathfinder had passed to NSP by the time of the September 1967 accident that shut down the operation.

94. The Company was informed by the construction firm of Black and Veatch in 1970 that the cost of complete decommissioning of the Pathfinder reactor would be $2,779,150.

An earlier (1968) Company study had estimated $1.5 million as the cost of that activity. NSP maintains no requirement for dismantling existed in 1976 (when the Commission decided Docket E-002/GR-76-934 and, as part of that decision, Pathfinder construction costs were allowed). The Company takes the position that until 1988, NRC regulations and rulings permitted utilities to maintain nuclear units in SAFSTOR.

95. The Pathfinder construction permit was issued on May 12, 1960, and an operating license was issued by the Atomic Energy Commission (AEC) in March 1964. At the time of the September 16, 1967, incident which shut the plant down, 100% power testing had not been completed at Pathfinder.

96. After receipt of its operating license and through the September 16, 1967 incident which shut the plant down, operation of Pathfinder was extremely

intermittent. The plant experienced numerous system and equipment difficulties and had a significant number of shutdowns. The Company reported to the AEC that it had difficulties with pressure control system hardware, steam flow meters, leakage from the main steam isolation valve, off-gas system hydrogen concentrations, faulty scrams, and undependable operation of the control rod drives. These operational difficulties and equipment shortcomings during the years of operation resulted in a large number of reactor shutdowns.

97. NSP accepted an "in-service" date of August 1, 1966, from Allis-Chalmers. The Company announced in May of 1966 that Pathfinder was in "commercial operation". However, the plant had yet to undergo successful start-up testing, or to reach the 100% power level and prove its continued capability to do so as of May 1966.

98. NSP wrote to the AEC on April 14, 1967, and noted that the AEC had "terminated its super heat development program". As a result, there was "no industry interest in the super heat concept". The Company noted that data generated by the continuation of Pathfinder post-construction research and development programs would be of "little or no use" because of the already highly-developed technology of water reactors.

99. One-hundred percent power was achieved by the Pathfinder reactor for about 30 minutes on September 12, 1967. However, Pathfinder ceased operations following the failure of a steam separator on September 16, 1967.

100. In an internal memorandum issued by NSP's power production department on April 30, 1968, entitled Pathfinder Atomic Power Plant Portrayal as a Training Facility, the Company's general superintendent of power production declared ". . . We have not given any serious consideration to use of

Pathfinder as a training facility. Although we had counted upon it as a training facility for our Monticello and Prairie Island personnel, it has let us down in this respect and we find it necessary to secure operator training by other means."

101. The Prairie Island nuclear power units are pressurized water reactors, which have very little in common with the reactor at Pathfinder.

102. Only three people received training at Pathfinder who subsequently worked at Monticello for a significant period of time after Monticello was in commercial operation. The reactor at Monticello uses different technology than that at Pathfinder.

103. Pathfinder did not provide sufficient benefits to NSP's ratepayers such that they should now pay for the decommissioning of the plant's nuclear reactor. When viewed from the perspective of the test year, Pathfinder was an experimental research and development project and never an operable nuclear power plant.

Discussion

The OAG and DPS argue that a decision on this issue now should be barred by res judicata or collateral estoppel considerations since the Commission's Order in the 1976 rate case covered the same issue. The Administrative Law Judge does not agree. NSP did not ask for expenses to cover total decommissioning in 1976, only for placement of Pathfinder into "SAFSTOR".

The Administrative Law Judge has concluded that NSP has not proven that Pathfinder has provided value to present ratepayers sufficient to require present ratepayers to bear any of the decommissioning expenses associated with its nuclear reactor. The $12.5 million requested by NSP in this proceeding is in addition to $9.5 million that NSP has already collected from ratepayers for abandonment and decommissioning of Pathfinder. NSP initiated the earlier request in a rate case 15 years ago. After a contested case hearing, the Company recovered from ratepayers $9.5 million in costs associated with both abandonment and partial decommissioning (placement of the facility in SAFSTOR). The Company did not advise the Commission in 1976 that a second phase of decommissioning would follow for which NSP would again seek recovery.

After a Company study set the cost of complete decommssioning at $1.5 million, and after the Company was informed by consultants two years later that the cost of complete decommissioning would be $2,779,150, it chose only to decommission Pathfinder partially, using the SAFSTOR method. These facts suggest that NSP's request to set aside funds for the decommissioning of Pathfinder over 20 years later, at a cost to ratepayers four to five times greater than could have been done in 1970, or over eight times that in 1968, comes too late and would be imprudent now.

Recovery of decommissioning costs from today's ratepayers would also result in a mismatch of costs and benefits with specific ratepayers. Present ratepayers would be responsible for costs associated with Pathfinder despite their receiving no electrical services or other benefits from the plant's operation.

It is noted that the request to recover decommissioning costs is also too late because the passage of time has deprived the PUC of the opportunity for full and complete evaluation of the monetary recovery NSP already has, or should have received following Pathfinder's abandonment in 1967. For instance, questions remain relating to the appropriateness of NSP's settlement with Allis-Chalmers. The Administrative Law Judge agrees with the OAG that documents discovered by the DPS during its audit of NSP strongly suggest that NSP's $3 million settlement with the manufacturer of the nuclear reactor was an inadequate sum which was agreed upon, at least in part, to avoid adverse publicity. It is noted that a letter dated May 27, 1969, from NSP's chairman to Allis-Chalmers states that the manufacturer owed NSP in excess of $10 million for Pathfinder's failure. Also left unresolved is whether NSP recovered any insurance money, or should have had the appropriate claims been made, for its losses at Pathfinder.

NSP bears the burden of the delay in deciding the appropriateness or merits of such issues. The Company also bears the burden of proof concerning its request for decommissioning costs. It is concluded that NSP has neither justified the delay nor met its burden of proof.

Regarding Pathfinder's usefulness as a training facility, there is no evidence that any such training benefited ratepayers by an amount equal to the total decommissioning costs requested in this case. The Company produced no cost study or other verifiable breakdown of such claimed training benefits. If training benefits do not outweigh training costs, it is difficult to conclude that NSP ratepayers ever benefited from Pathfinder. It is more clear that ratepayers being asked to pay its decommissioning expense in the test year and future years will not benefit.

The Judge has found that Pathfinder's nuclear facility is not "used and useful". The used and useful standard holds true for expenses as well as rate base items. Philadelphia Elec. v. Pennsylvania Public Utilities Commission, 61 P.A. Comm. Ct. 325, 433A.2d 620, 625 (1981); Citizens Action v. Northern Indiana Public Service Company, 486 N.E.2d 610 (Ind. 1985), cert. denied 106 S.C. 2239 (1986). In Citizens Action, the Indiana Supreme Court stated:

> "Any allowable operating expenses must have a connection to the service rendered before it can be recovered through retail rates. This connection is established when the operating expense is incurred as a result of the process whereby existing 'used and useful' property . . . is employed to produce the product or commodity . . . ratepayers receive." Id., at 614.

In Citizens Action, the utility, like NSP in this case, characterized a cancelled plant "as a reasonable untertaking by (the utility) to meet its duty to serve". Id., at 614. The Court rejected that reasoning, calling the commission's approval of such expenses a charge to consumers "for reasonable and prudent attempts at service that fail and that provide no benefit to ratepayers." Id., at 614.

Regardless of whether Pathfinder was used and useful at one time, its nuclear reactor is not now in service and has not been in service for over two decades. The expenses related to the decommissioning of Pathfinder's nuclear operation do not provide any service to NSP's customers. Therefore, no costs relating to such decommissioning should be included in rates. NSP's proposed placement of those costs in expenses, rather than splitting them between rate base and expenses, does not avoid scrutiny under the "used and useful" standard.

While the Judge agrees with NSP that consideration of this issue is not barred by the 1976 rate case Order, it is noted that NSP was informed at that time of the costs for total decommissioning, which were several times less than they are today, but elected not to do it or to seek recovery for it in rates. It is difficult to decide the prudency of that decision, made 15 to 20 years ago, to leave the reactor in SAFSTOR until required to do more. However, the eventual total dismantling was foreseeable then, whether officially required or not. It would be inappropriate to recover expenditures for that dismantling at this late date. If the PUC decides to allow NSP recovery of these expenses, then it is reasonable to follow MEC's suggestion and apportion the recovery over the remaining life of the fossil-fuel unit at Pathfinder.

Chippewa Land Sale

104. In 1988 and 1989, NSP-Wisconsin, a wholly owned subsidiary of NSP, sold more than 8,500 acres of land it owned at the Chippewa Flowage near Hayward, Wisconsin to the State of Wisconsin and to the federal government. NSP-Wisconsin (NSP-W) realized a before-tax gain of just under $8,600,000 on the sales and an after-tax gain of $5,588,000.

105. NSP purchased the land in 1920 for less than $5.00 per acre, and held it as a part of its original federal license requirement, which requirement was lifted in 1984.

106. The land became available for sale when the FERC license on the Flowage expired and NSP obtained an exemption from FERC for future licensing.

107. The OAG argues that the gain on the sale of land should be shared with Minnesota ratepayers. They advocate an adjustment whereby NSP's rate base for the test year would be reduced by $3,426,000 and net operating income would be increased by $1,371,000.

108. The OAG argues that the land was acquired for a public utility purpose because it was recorded in a utility plant account for most of the time it was held by NSP (until 1987). Therefore, the costs associated with the Chippewa Flowage facility were passed on to ratepayers during that time. The statement by the Company that the land was recorded in an account named "Utility Plan Leased to Others" but should not be considered "utility property" prior to its transfer to a non-utility account creates, for the Intervenors, the opposite inference -- that the property was utility property prior to 1987.

109. NSP has not shown that the Chippewa Flowage land was placed in a non-utility account at the time of the original purchase. From this, the Intervenors infer that the land was included in NSP-W's rate base, upon which ratepayers paid a return. The Intervenors argue further that Minnesota ratepayers supported the land through payment of electric rates. Their conclusion is based on an assertion that prior to the sale, NSP-W leased the land to its subsidiary, Chippewa and Flambeau Improvement Company (CFIC). CFIC controlled the water flowage through the area and charged utilities for the use of the water. NSP used the water for the generation of electricity. Therefore, the water tollage charged by CFIC was part of NSP-W's cost of producing power, which cost flowed through the Interchange Agreement between NSP-W and NSP-Minnesota and, therefore, was in part paid for by Minnesota ratepayers.

110. NSP argues that the gain on the sale of land, even as to NSP-W, was for the benefit of shareholders, not ratepayers, since NSP-W's ratepayers never provided to shareholders a return of the investment in the land. The Company notes that tolls paid to CFIC were for use of the water in the Flowage, not of the surrounding land.

111. In the past, NSP has flowed through losses incurred on the disposal of property acquired for a public utility purpose. For example, Minnesota ratepayers paid for the amortization of the cost of the abandonment of the Tyrone nuclear project. The Intervenors argue that NSP should treat its gain on sale of the Chippewa land in a consistent manner.

112. NSP also argues that ratepayers should not share in the gain because land is not a depreciable asset and ratepayers

do not pay a return on land based on the market value of the property. The Intervenors maintain that depreciability is irrelevant to the issue of whether or not NSP ratepayers should share in the gain because, while land which is included in rate base must be included only at original cost, Minn. Stat. 216B.16, subd. 6 does not exclude non-depreciable property from rate base.

113. The OAG argues that the PUC has determined that any gain on utility property belongs to the ratepayers, and that the Commission has not excluded land as an exception to that principle. In support of this proposition, the

OAG cites the Commission's Order in Minnesota Power's last rate case (Docket E-015/GR-87-223) where the Commission ordered that gains on utility properties belong to the ratepayers. It is noted that in that case, Minnesota Power (MP) did not propose to segregate the sales of land regarding either the sale of a 40% share of its Boswell 4 power plant to NSP or in accounting for gain on the sale of MP's ownership interest in the Coyote plant.

114. NSP's argument that the Uniform System of Accounts dictates that the gain must be given to shareholders is contradicted by the ruling of the Minnesota Supreme Court in In the Matter of the Petition of Continental Telephone Company of Minnesota, 389 N.W.2d 910 (Minn. 1986) wherein the Court stated ". . . Nothing in the federal regulations or the Minnesota rules suggests that the system of accounts is determinative of the treatment of any item for purposes of setting rates or that the system deprives MPUC of its power or absolves it of the duty to decide the issues before it and to set just and reasonable rates." 389 N.W.2d at 915.

115. NSP contends that the Commission cannot pass through the gain to Minnesota ratepayers unless the Interchange Agreement is amended by FERC. However, amendment of the Agreement must be initiated by NSP. NSP made such an application to FERC in connection with the abandonment of the Tyrone plant, and the Minnesota Supreme Court decided in Northern States Power Company v. Minnesota Public Utilities Commission, 344 N.W.2d 374 (Minn. 1984) that 87% of the fixed charges of the abandonment costs for Tyrone should be borne by Minnesota ratepayers. The OAG argues that NSP has deliberately failed to request such an amendment for the gain on the sale of the Chippewa Flowage land. Thus, NSP is arguably taking the position that its ratepayers stand at risk for all losses but can receive no gains. The OAG maintains that such a position is fundamentally unfair. The OAG also argues that if the Commission believes it lacks authority to impute the Chippewa land sale gain to ratepayers, because the Interchange Agreement is controlled by FERC, then the PUC should require NSP to seek approval from FERC to share the gain with ratepayers. Under the suggested scenario, the PUC could disallow the gain for purposes of final rates but make the rates subject to refund in the event FERC approves NSP's request for sharing.

116. The Administrative Law Judge accepts the arguments advanced by the OAG noted in the above Findings of Fact and finds that it is appropriate to reduce NSP's rate base by $3,426,000 and increase its net operating income by $1,371,000 for test year to reflect a flow-through to Minnesota ratepayers of an appropriate portion of the gain made by the sale by NSP-W of Chippewa Flowage land. He is not persuaded by NSP's arguments that the land was not utility property or that Minnesota ratepayers never paid NSP-W a return on its investment. As to the transaction's absence from the Interchange Agreement, it is NSP that controls the approach to FERC for an amendment of the Agreement to allow a pass-through of the gain on the land sale. The PUC can Order NSP to make that approach to effectuate its intent. The Judge is persuaded that not recognizing this gain would result in rates that are not just and reasonable and would be fundamentally unfair to Minnesota ratepayers.

NSP's Budget Process

117. In its Order dismissing NSP's last rate filing, the PUC found:

> Because of grave doubts about the accuracy, reliability, and predictive value of the test year budget data

> submitted by the Company, the Commission will deny the requested rate increase . . . . The Commission concludes that the Company's filing does not provide a reliable foundation from which to determine just and reasonable rates.

In the Matter of the Application of Northern States Power Company, Docket E-002/GR-89-865, pp. 10-11 (8/28/90).

Following the denial of its rate increase request, NSP took steps to revise its budget process and the current filing reflects those changes.

118. DPS witnesses Lusti, Layton and Chavez reviewed NSP's budget system and verified the implementation of several changes from NSP's last rate case filing, including:

A. The use of first-year budgets for the rate case test year as opposed to forecasted second-year budgets, reducing the timespan between NSP's projections and actual expenditures;

B. Presentation of documentation linking the rate case forecast to actual 1989 expenditures;

C. An automated budget information system, called NCAP, which improves the reliability and auditability of NSP's capital budgets;

D. Elimination of reimbursable and non-utility projects from the rate case filing;

E. Elimination of the corporate contingent fund, which Intervenors alleged had allowed ratepayer dollars to be divested to non-utility, non-Minnesota projects; and

F. Adoption of guidelines to levelize the apparent "rollercoaster" characteristics of the Company's budgets.

The above-noted changes revising NSP's budget process affected the Company's 1991 rate case budgets. The DPS review team believes the Company has made a good faith effort to address concerns stated by the Commission in its Order dismissing the last rate case. They believe NSP's current budget process can provide the audit trail necessary to determine whether NSP actually uses the forecasted test year expenditures to fund Minnesota jurisdictional, electric utility projects.

119. In addition to its overall review of NSP's budget process, the Department conducted an in-depth review of specific areas of the budget to identify any systematic problems or errors. The audit team identified the "driver" behind the increases in both the capital and DOE (Department Operating Expenses) budgets, and then examined each budgeted Improvement Requisition (IR) and expenditure in the specific areas. The Department's examination identified no systematic problems or errors with NSP's capital budget.

120. For detailed review of NSP's capital budget, the DPS selected the Nuclear Power Supply area, which was one showing a significant increase between 1990 and 1991. In addition, Power Supply historically constitutes a large part of NSP's capital budget and, in the past, the auditors had observed significant deviations from budget within the Power Supply area. Based on that history, the audit team examined every Nuclear Power Supply IR with a forecasted expenditure for the test year.

121. With respect to the DOE budget, the Company summarizes that budget using ten different DOE lines. The DPS began its investigation of that budget by reviewing the Company's breakdown by DOE line. The review showed that DOE line 16 -- "Other Expenses" -- more than doubled since 1989 and accounted for 45% of the total increase in NSP's DOE budget since that year.

In its investigation of line 16, the audit team reviewed every cost element within that line (roughly 800 to 1000 cost elements). Cost element MS16 accounts for 38% ($28.5 million) of the total $75.6 million budget within DOE line 16. The

Department decided also to examine every expense budgeted within that particularly large cost element.

122. NSP builds its DOE budget lines by budgeting individual expenses. The Company budgets these expenses by using three different tools: cost elements; cost activities; and projects. A cost element groups similar expenses within a single DOE line. Cost activities and projects cross DOE lines. When the Company determines expenditures using cost activity or project identifiers, the budget system creates a miscellaneous cost element within each applicable DOE line and assigns expenses to that cost element. For DOE line 16, this cost element is MS16 (Miscellaneous Other Expenses).

123. The DPS investigation identified one cost element and several budgeted expenditures within element MS16 which should be removed from NSP's test year operating expenses. The items total roughly $575,000, which account for three-fourths of one percent of the total DOE line 16 expenditures of $75.6 million. Based upon its investigation, the Department concludes that there are no systematic problems or errors calling into question the underlying reliability of NSP's Department Operating Expense (DOE) budget.

124. MEC maintains that despite its efforts to address budgetary problems noted by the Commission in the last rate case, that NSP's budget still has serious fundamental problems that require a large adjustment in its revenue requirement in this case. Specifically, MEC recommends a $26,923,000 adjustment downward, $16,829,000 of which is related to budgeting problems but not tied to specific adjustments. The specific adjustments recommended by MEC will be discussed in later Findings.

125. MEC maintains that NSP's test year DOE budget cannot be compared to prior budgets or to actual expenses for prior years. MEC notes that the Company began with two different figures for its 1989 DOE actual expenditures, that individual departments changed, and that such shifts and changes have complicated its review.

126. In response to MEC's concern that there was no way to determine if current budget levels for each department are reasonable or necessary because no one can determine what was included before and what is included now, the Company explained that it had changed "roll-up structures". NSP's roll-up

structure is a detailed organizational chart directing the flow of budget information to appropriate decisionmakers through which departmental budgets are reviewed. Under NSP's changes, different expense categories are now reported in different departments. NSP's explanations fail to persuade MEC that the test year budget can be compared to prior period budgets and prior period actual levels of expenses.

127. On or about August 10, 1990, NSP changed its basis for its 1991 first-year budget from the June 27, 1990 forecast for 1991 to 1989 actual results. MEC maintains that, as a result of this change, Intervenors cannot be sure which base was used by each person responsible for different parts of the budget. Some may have used 1989 actuals as the base while others may have used the June 27, 1990 forecast. MEC argues that the inability to determine which base each department used shows that departments used inconsistent starting points and also raises the general question of whether NSP's DOE budget is reliable.

128. Frustrated in its attempt to analyze specific budget increases, MEC tested the reasonableness of NSP's overall DOE budget by adjusting 1988 actual expenditures by the rise in the Consumer Price Index (CPI) since 1989. Comparing the results, MEC discovered that NSP's test year DOE budget exceeded 1989 actuals adjusted for inflation by $30,390,000 ($26,923,000 on a Minnesota jurisdictional basis). As a result, MEC recommends the downward adjustments noted above.

129. Another Intervenor criticizing NSP's budget process in this case is North Star Steel. North Star maintains that since each of NSP's 224 department managers are responsible for development of their own budgets, there is no "basis" for the Company's overall budget. During the budgeting process, NSP distributed budget guidelines derived from the 1988 adjusted budget escalated by the level of the estimated Consumer Price Index to each department manager. North Star maintains that these guidelines are actually "targets" for each manager. If a manager budgeted underneath the guideline amount, that manager could lose influence and prestige in the Company. If a manager budgeted over the "target", they would face scrutiny by higher-ranking personnel. From this, North Star concludes that individual department budgets tend to reflect the targets established, rather than the departments' actual requirements.

130. North Star attacks the use of 1988 budget amount as the basis for the Company's departmental expenditure targets because that budget was designed for use as a test year budget, which the Company had a tendency to inflate artificially. In addition, North Star criticizes the use of the CPI, as opposed to an inflation index closer approximating the situation found within a utility company, as the escalator for establishment of department expenditure targets.

131. NSP maintains that the use of the Consumer Price Index as an inflator merely served as a guideline to department managers in development of their test year budgets, and that the budgets were developed independently, based on each department's needs. It was only after that development that the department's totals were compared to the earlier base adjusted by the CPI. North Star does not see the distinction, and argues that the use of the estimate of utility O & M expense increases published by Data Resources, Inc. (DRI) is a more appropriate inflation index to be utilized.

132. North Star also criticizes NSP for failure to provide financial information in a format using the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USOA). Rather than using the USOA as its format for the budget test year, NSP summarized its 1991 test year estimated Operating and Maintenance expenses into seven functional categories corresponding to aggregated FERC accounting classifications. North Star maintains that such aggregation obscures any significant changes that might be forecast for any particular account and prevents ready comparison to historical data or to the data of other utilities.

133. North Star concludes that the Company's 1991 test year budget must be adjusted before it can serve as a reliable basis for rates. The most appropriate adjustment would be to limit the increase in the Company's budgeted DOE to the level of 1989 actual expenses adjusted by the amount of DRI's Operating and Maintenance price change escalators for utilities, as suggested by North Star witness Mr. Solomon. If that adjustment, which will result in a reasonable basis for fixing revenue requirements in this case, is not made by the PUC, the only other reasonable alternative seen by North Star would be to reject the test year as unreliable and dismiss NSP's rate case again.

134. It is found that NSP's test year expense forecast provides a reliable basis for setting rates. The "normalizing" adjustments proposed by MEC and North Star to the test year Departmental Operating Expense forecast are not appropriate. There is no basis to limit NSP's expense increases in any particular year to the rate of increase reflected in the CPI or DRI indices.

Discussion

In response to MEC's criticisms, NSP points out that the fact that it changed its statement of 1989 actual DOE expenses, in total and for individual departments, between the last rate case and this one and that it changed its budget base after the budget processing had begun do not amount to deficiencies that would affect the ultimate reasonableness of its test year budget for this rate case. NSP's restatement of the 1989 actual DOE expenses was made for the purpose of facilitating comparison to the 1991 budget. The restatement was made by utilizing updated common allocation factors so that the 1989 information was grouped in a manner consistent with the 1991 test year budget. The amount of 1989 DOE expenses for the Minnesota company did not change, only the amount allocated to electric utility changed by virtue of changes in common allocation factors.

MEC's argument suggests that a utility should never change its roll-up structure of Departmental Operating Expenses, an argument that ignores business realities and precludes opportunities to make improvements in the budgeting process. NSP's decision to restate historical information so that it is consistent with changes made in the current budget process allows for full comparability and is appropriate.

MEC's argument regarding the change in the amount of 1989 actual costs is misplaced. The difference is only $44,972 out of over $449 million. Clearly, a 1/100th of one percent change is not material.

MEC's criticism of NSP for changing the basis of its test year projections from June 27, 1990 forecast data to the use of 1989 actual data is also misplaced. NSP made that change in order to facilitate comparison of test year budget data to historical data, responding to Intervenors' criticisms and the concerns stated by the Public Utilities Commission when it denied NSP's last rate increase request. NSP's budget creation process lasts approximately five months (August through December) of any year. The change to use of 1989 actual data occurred within the first ten days of that five-month period. Therefore, MEC's concern that the change was made "after the budget creation process had already begun" is not crucial -- the change occurred in ample time for departmental budgeters to make use of the 1989 actual data.

Regarding North Star's criticisms, which center around NSP's distribution of guidelines to its managers, the Company responds that the distribution of guidelines was designed to reduce subjectivity in the departmental "budget create" process and that the figures were truly guidelines, not "targets".

North Star's criticism of the specific guideline used by NSP (the 1989 test year adjusted by the CPI) suggests that those two forecasts, taken together, form the basis for the test year budget submitted in this case. The Administrative Law Judge is not so persuaded. NSP's use of historical data in the budget process is clear from the record. The Company used actual 1989 as its budget base. The record also shows that NSP budgeters did not merely extrapolate from 1989 actuals to the test period by mechanical application of some inflation index. The 1989 actual figures provided relevant information, but were not the foundation for departmental budgets.

The use by NSP of 1989 actual expenditures addresses the Commission's concern that budgeters make historical comparisons to a common base year. The record reveals that NSP's budget is the project of department managers' independent assessments of the needs for their departments, and that the guidelines, using CPI inflators, are merely used as one check for the reasonableness of the budget for each department.

In connection with this filing, NSP supplied 38 volumes of budget documentation which gave Intervenors and the Commission the ability to review the details of the budget for expenses and to analyze the reasons for changes from historical levels. In contrast to the complaints of MEC and North Star, the DPS has conducted the most detailed audit of NSP's budget documentation and found that the Company's budgeting and forecasting methods provide reliable bases for setting rates. The Administrative Law Judge agrees with the Company and the Department of Public Service in this regard. While MEC and North Star raise legitimate concerns about NSP's guideline in this proceeding, particularly its use of the CPI as an inflation index, the record does not demonstrate that the guideline infected NSP's budget in such a way as to call into question the entire budgeting process, nor does the record call for a direct change to NSP's budget process to address this issue.

NSP has substantially revised its budget process and the Department's investigation revealed no systematic problems or errors which call into question the reliability of that process as a basis for setting rates. The gross adjustments in the revenue requirement advocated by MEC and North Star should be rejected.

The DPS is concerned, however, that NSP's newly implemented policies, procedures and systems have no current track record. Therefore, they recommend requiring the Company to make certain additional information available at the time of its next rate filing. Specifically, the DPS recommends that the Commission should require NSP to provide a month-by-month accounting of all transactions for each area contingent fund and a year-end summary report of project substitution within each area contingent fund with its next rate filing.

The Department recommends further that NSP have available for the PUC and Intervenors at the time of its next filing copies of all work papers and notes used in developing the Company's budget, similar to the 38 volumes of documentation presented in the current proceeding, "bridge" schedules showing all adjustments to rate case numbers from the unadjusted budget numbers (similar to the "bridge" schedules provided by NSP after their filing in this case) and translation reports linking cost elements, cost activity and project budgeting mechanisms on a common and consistent basis. Such reports would ensure an accurate accounting for expenses contained in "default" cost elements such as MS16. The Department urges, and the Administrative Law Judge agrees that implementation of such recommendations will help assure future verification of NSP's expenditures and aid review of the Company's subsequent rate filings.

Unbilled Revenues

135. The OAG argues that NSP's test year revenues do not reflect the full amount of revenues associated with the sale of electricity during the test year. However, all costs related to the sale of energy during the test year are included by NSP. The OAG proposes an adjustment to reflect what it believes to be the proper amount of test year revenues and an "accumulated unbilled revenue" adjustment to amortize the alleged yearly buildup of this difference.

136. At the end of any given month, NSP records all expenses associated with providing electricity to customers that month. However, the Company has not recorded all revenues associated with electricity, due to the lag time involved, before those revenues are billed to its customers. The OAG contends that greater revenue is usually left unbilled at the end of each December than is offset by amounts NSP receives in January of the same year, due to increased electric usage, increasing customer base and rate increases.

137. The existence of unbilled revenues is caused by timing differences between the recording of revenues and the recording of costs. NSP records revenues on its books at the time it reads customers' meters, but it records expenses at the time of actual expenditure or through accruals. Therefore, at the end of any given month, the Company has recorded all expenses associated with providing electricity to customers that month but has not recorded all revenues associated with those expenses. Approximately one-half of the revenues recorded for any month under the Company's accounting system relate to expenditures associated with the prior month.

138. The OAG argues that for the test year, end-of-the-year unbilled revenues amount to $57,031,874, whereas beginning-of-the-year unbilled revenues are only $55,570,231. The difference, $1,461,643, is proposed for

inclusion in revenues for the 1991 test year. Such inclusion would lower NSP's revenue requirement.

139. NSP argues that the recognition of such unbilled revenues would amount to a fundamental change in regulatory and accounting policy affecting all utilities and should only be considered in a generic proceeding.

140. The timing difference noted above would have no effect on rates if the amount of electricity provided each year and rates for that electricity remained constant over time. Under those assumptions, the unbilled revenues of the year preceding the test year and recorded at the beginning of the test year would equal the revenues left unbilled at the end of the test year. Thus, ratepayers would receive full credit for all test-year revenues. In NSP's case, however, greater revenue is usually left unbilled at the end of each year and is offset by

amounts NSP receives at the beginning of that year.

141. The recognition of unbilled revenues is within generally accepted accounting principles. The Commission has recognized test year unbilled revenues in setting rates. NSP, Docket G-002/GR-86-160 (1987), at p. 24; Midwest Gas, Docket G-010/GR-90-678 (1991), at p. 19.

Without an adjustment for test year unbilled revenues, NSP will receive credit for expenses but the ratepayers will not be credited with the revenue associated with those expenses.

142. It is appropriate to impute unbilled revenues of $1,461,643 into NSP's operating revenues for the test year.

143. The OAG proposes that, in addition to booking the test year unbilled revenues of approximately $1.5 million, accumulated unbilled revenues in the amount of $55.6 million should be recognized by amortizing them over a ten-year period. A ten-year amortization would increase test year unbilled revenues by another $5.6 million.

144. Recognizing the accumulated unbilled revenues as requested by the OAG results in a gross mismatch. A mismatch occurs because the OAG proposal combines approximately 12-1/2 months of revenue with only 12 months of expenses. While that mismatch is mitigated by the OAG's proposed ten-year amortization, it is not eliminated. See NSP, Docket E-002/GR-85-558, 6/2/86, p. 35. The OAG proposal ignores the fact that revenues not received by December 31 of past years to match with late-December expenses have all been received in the subsequent January, except for those in the (forecasted) test year under examination in this proceeding.

TRANSCO Study

145. As a result of a cost savings study performed for its transmission (TRANSCO) area, NSP has decided to implement measures saving several million dollars. MEC takes the position that approximately $5,319,000 (Minnesota jurisdiction) should be reduced from operating expenses because NSP's filing does not recognize the implementation of the TRANSCO recommendations during the test year.

146. The OAG does not dispute NSP's contention that it has recognized all savings implemented pursuant to the TRANSCO Study recommendations during the

test year, but recommends that NSP's expenses be adjusted in the amount of an additional $400,000 for savings to be implemented during 1992 pursuant to the TRANSCO Study.

147. The adjustments advanced by MEC and OAG related to NSP's TRANSCO Study are inappropriate. NSP has recognized the test year savings and incorporated them into its budget for this rate case. To follow MEC's recommendation would reduce NSP's expenses inappropriately for an item already taken into account. The OAG adjustment is inappropriate because it would reflect expenditures that will not occur until after the end of the future test year. Changes expected to occur after the test year should not be used to adjust costs budgeted for the test year. In addition, the savings represented by the reduced expenses will not be realized until that point in the future (1992).

King Plant Rotor

148. As part of this rate case NSP proposes a five-year amortization of the cost of the replacement rotor at the Allen S. King Generating Plant, and that the unamortized balance be included in rate base.

149. The Company originally planned both to replace and to refurbish a damaged rotor at the King Plant in order to retain it as a spare part. In Docket E-002/GR-87-670, the Commission allowed the cost of the new rotor to be capitalized and included in rate base. Subsequent analysis showed that the old rotor could not be economically refurbished. Consequently, the Company proposed that it was appropriate to capitalize the cost of the new rotor. Under generally-accepted accounting principles, the replacement cost would normally be expenses for the year in which it was incurred.

150. In 1988, NSP proposed to the Commission that the cost of the new rotor, which had previously been included in rates as a capitalized project, be capitalized over 5 years. In Docket E-002/M-88-923, the PUC decided, on December 15, 1988, to approve NSP's proposed amortization. On February 23, 1989, the Federal Energy Regulatory Commission also approved the five-year amortization method.

151. MEC argues that the King Rotor amortization expense ($2,187,000) proposed in this case should be excluded from NSP's cost of service. This adjustment, coupled with its effect on reducing rate base, would reduce NSP's revenue requirement by $1,915,000.

152. MEC argues that NSP's proposed treatment of the King Rotor expense represents an improper attempt to recover a past operating cost that is not representative of the period for which rates are being set (the 1990 test year). Since the rotor repairs were completed in June 1988, and NSP does not expect to incur any cost with respect to removal and repair of the King Rotor during the test year, MEC maintains that the repair and replacement costs are not representative of the period for which rates are being set, and the inclusion of such costs would violate basic rate making principles, which hold that a utility may not set rates to recoup past losses.

153. MEC characterizes the Commission's Order of December 15, 1988 in Docket E-002/M-88-923 as merely approving an accounting change, with reservation of a determination on ratemaking treatment.

154. MEC maintains that NSP's proposal to account for the cost of the new rotor by amortizing the expense over five years is merely a change in plans that involves new accounting treatment. NSP argues that once the decision was made to amortize, rather than expense the King Rotor repair and replacement costs that it would be completely unfair to change the methodology in the middle of the amortization period and deny the full return of the investment through either mechanism.

155. The Administrative Law Judge agrees with NSP on this issue. The Commission's "reservation" of determining of ratemaking treatment in its Order of December 15, 1988 is interpreted to mean simply that Docket E-002/M-88-923 was not a rate case and that the Company would have to wait until it filed its next rate case before the effect of the newly-approved accounting methodology would appear in rates. It is appropriate to reject MEC's proposal to disallow the amortization expense and rate base treatment for an obviously prudent expense such as replacement of the King Rotor.

156. MEC's contention that the King Rotor replacment should be treated as any other operation or maintenance cost, and expensed in the year incurred, has the effect of excluding the cost since it was incurred prior to the test year. Such analysis ignores past regulatory treatment of these costs and would be inappropriate. No Intervenor objected to NSP's prior capitalization of the costs, or its subsequent request to commence the amortization. The Administrative Law Judge agrees with NSP that it is now too late to "redo history" and treat these costs as though they had been expensed in a prior period.

Economic Development

157. The Company proposes to recover $431,187 in test year expenses for Economic Development. The DPS, OAG and MEC are opposed to allowance of costs of NSP's economic development programs.

158. The DPS argues that NSP has not established a sufficient connection between economic development and the provision of electric service and that NSP's economic development programs are not cost effective. The OAG asserts that NSP has not proven that economic development costs are an "integral part" of electric service or that economic development is a "vital and necessary part of providing electric service". MEC maintains that economic development costs are advertising expenses which are disallowed by statute.

159. On May 24, 1991, a new statute, Minn. Stat.   216B.16, subd. 13, took effect. It reads:

> Subd. 13. Economic and Community Development. The Commission may allow a public utility to recover from ratepayers the expenses incurred for economic and community development.

NSP maintains that the new statute demonstrates a clear legislative intent that economic development expenses are recoverable in rates and, of itself, establishes the connection between economic development and the provision of electric service.

160. Although the Rate Case Stipulation in NSP's 1988 rate case allowed for a 50-50 split of economic development costs between shareholders and ratepayers, the PUC disallowed economic development costs in its June 23, 1988 decision in that docket. The Commission held that NSP had not demonstrated a strong enough connection between economic development and the statutory factors found in Minn. Stat.   216B.16, subd. 6 to allow inclusion of economic development costs. NSP, Docket E-002/GR-87-670, at p. 21. The factors include the public's need for adequate, efficient and reasonable service and the utility's need for sufficient revenue to enable it to supply such service, including its need to earn a fair return on its investment.

161. NSP has not demonstrated a sufficiently strong connection between its economic development programs and the provision of utility service, as required by the Commission in the Company's 1988 rate case. In addition, the Company has not demonstrated that its economic development investment is cost-effective. The Company has not met its burden of showing that it is just and reasonable for ratepayers to bear the costs of its economic development programs. It is appropriate to deny the Company's request to include $431,187 in operating expneses for economic development for recovery in this rate case. The recent legislation, which states the Commission "may" allow a public utility to recover from ratepayers the expenses incurred for economic development, does not remove the Company's burden to establish a strong connection between economic development expenses and the public's need for adequate, efficient and reasonable service.

162. NSP presented the results of a survey of its customers regarding economic development expenses, which survey purports to demonstrate that NSP's customers favor economic development. NSP also presented a cost-benefit analysis. Evidence of the popularity of a program or other public opinion responses is immaterial to the question of whether NSP's economic development activity is a vital and necessary part of providing electric service such that monopoly ratepayers should pay for the program.

Whether a program is cost-effective is not dispositive of whether it is related to the provision of electricity such that ratepayers should fund it and, to the extent it is related, the DPS demonstrated that NSP's economic development programs are not cost-effective.

163. In support of its economic development programs being included for rate recovery, NSP offered generalized information on the benefits of additional sales of electricity and cited other general benefits such as additional jobs, economic activity, income and taxes. The DPS requested detailed information to assist it in determining whether the Company's economic development programs demonstrated an adequate connection to the statutory factors discussed by the Commission in the 1988 rate case. NSP replied that it could not provide the information requested by the Department since it did not track its economic development accounts or clients in such a way which would enable it to answer the Department's questions.

164. To the extent NSP maintains that it no longer must show a connection between its economic development programs and the provision of utility service as required by the Commission in its last Order on this issue, NSP relies on the above-quoted statute for provision of such a connection. However, the statute merely clarifies what the Commission has already recognized -- that utilities may recover these expenses upon showing a sufficient connection to the other statutory factors of Minn. Stat. 216B.16.

Advantage Service

165. NSP's Advantage Service (AS) is an unregulated appliance maintenance program. The unregulated operation uses some regulated facilities in its operations such as mailing lists, the regulated billing system and referrals from NSP's utility representatives.

166. The OAG is concerned about possible cross-subsidy of unregulated business by regulated operations of NSP through mailing lists compiled for the regulated operations that could be used for unregulated operations, the use of the regulated billing system and any referral to Advantage Service from NSP's utility service representatives. The actual adjustments found by the OAG's analysis-investigation are insignificant, and the OAG makes no recommendation for a change in NSP's revenue requirement as a result. However, the OAG requests a ruling on these issues regarding cost separation principles so that they can be imposed in future cases.

167. The OAG takes the position that for each item, AS should pay NSP a competitive price that recovers the costs and makes a fair contribution to overhead, so as to assure that AS is fully compensating NSP and its ratepayers for the services it

receives from the regulated entity. NSP maintains that AS is paying all costs associated with the services it is providing through allocation or direct assignments.

168. Regarding customer lists, NSP maintains that no adjustment is necessary because AS has not done any general distribution mailing in 1991 and has no plans to do so in the near future. As to use of NSP's billing system, NSP acknowledges that AS uses those facilities. As a result, the OAG believes that NSP should pay a market rate which recovers both direct costs and makes a contribution towards fixed costs for whatever proportion of billing system costs would be appropriate.

169. NSP argues that no adjustment is necessary for use of the regulated billing system because AS did not cause NSP to invest in the assets used for billing. The OAG maintains that it is unfair to require ratepayers to pay a return on the billing system assets without also requiring AS to pay a similar return.

170. The OAG argues that an adjustment should be made reflecting the fact that NSP's service representatives spend time referring customers to NSP's unregulated AS. NSP admits that its Customer Business Office operators respond to questions about AS and refer customers to it. However, NSP does not allocate any service representative's time to AS. The Company admits that its Customer Business Office spends two hours per month on AS.

171. It is appropriate to require NSP's Advantage Service to properly compensate NSP's electric operations for the use of NSP's mailing list, billing system and Customer Business Office personnel so that such costs will be properly accounted for in future interim rates and future rate case filings.

172. The OAG recommends further that NSP provide its customers with the option of having their names removed from mailing lists NSP provides to unregulated affiliates or competitors. NSP did not respond specifically to this proposition. It is appropriate to order NSP to provide notice to customers through billing inserts and customer contact of the option to be dropped from mailing lists provided to others by NSP.

Uncontested Rate Base Adjustments

173. NSP filed this rate case using a fully forecasted test year of January 1, 1991 to December 31, 1991. NSP's test year rate base consists of an average of beginning and end-of-year plant balances. NSP based the beginning balances on actual data through October 31, 1990 and projected data for the final two months of 1990. The Company then based the end-of-year balance on the beginning balance, plus the addition of 12 months of projected data for 1991.

174. In its January 28, 1991 filing, NSP overstated the October 31, 1990 plant balances in the Functional Plant in Service (FPIS) system by $5,504,669 on a Minnesota company basis. An adjustment is required to reduce the plant balances to the level accurately reflecting NSP's starting point. The adjustment reduces the jurisdictional test year plant in service by $4,881,000, the reserve for depreciation by $97,000 and the accumulated deferred income tax by $40,000. NSP accepts these adjustments, which were recommended by DPS witness Dale Lusti.

175. Regarding Information Services chargebacks, the DPS investigation identified the item in both test year operating expense and capital expenditure budgets. To prevent such "double counting", the DPS suggested and NSP agreed to adjust the budget for chargeback expenses. The removal of chargebacks from test year capital expenditures results in a net decrease to rate base of $1,324,000, which was incorporated into NSP's rebuttal filing.

176. The DPS investigation also discovered that NSP had charged $1,927,000 in purchasing costs to test year operating expenses and included a comparable amount in its capital expenditure budget. The Company agreed to an adjustment removing those monies from test year capital expenditures, resulting in a net reduction to rate base of $1,649,000, which was incorporated into NSP's rebuttal filing.

177. NSP filed its annual remaining life depreciation study with the PUC on April 19, 1991, Docket E-002/B-91-300. NSP proposed that the Commission incorporate the new depreciation rates contained in that study into this proceeding when approved. The DPS and OAG agree, and all three parties have incorporated the newly filed rates into their proposed schedules for this rate case. NSP's newly filed rates reduce its overall jurisdictional revenue requirements by approximately $4.8 million. If they are approved by the Commission during the pendency of this rate case, NSP's proposed rates are found to be reasonable and appropriate for inclusion in rate base. If the Commission does not approve the rates as proposed, then the test year depreciation expense should be recalculated to incorporate the Commission-approved rates.

Unburned Nuclear Fuel

178. At the end of the productive lives of NSP's three nuclear reactors, there will remain a total unrecovered balance of unused nuclear fuel in the amount of $123.1 million. The fuel remaining at the end of these plants' lives cannot reasonably be salvaged. NSP's proposal to adopt a sinking fund amortization will build a reserve to recover the cost of such fuel over the remaining lives of the three nuclear plants and will avoid charging the total amount to customers who are not benefitted by the fuel.

In Docket E-002/D-90-184, the PUC approved NSP's nuclear decommissioning cost study and proposed funding methodology, including the sinking fund for end-of-plant life nuclear fuel. The Company's proposal to collect $1,465,000 during the test year for nuclear fuel which will be unburned at the end of each nuclear unit's life is reasonable and appropriate.

CIP Financial Incentive

179. The recently-approved CIP financial incentive and cost recovery mechanism for NSP divides CIP expenditures into two categories -- capitalized (rate based) and non-capitalized. The incentive amortizes the capitalized expenditures over a five-year period and awards a five percent equity bonus. The amortization amount and the normal and bonus returns are then placed in NSP's annual CIP revenue requirement. All other CIP expenditures, including research projects and non-capital load management expenditures, are placed directly into the Company's annual CIP revenue requirement. For the 1991 test year, the first year of the five-year amortization process, revenue requirements will be less than actual CIP expenditures.

180. The Commissioner of the Department of Public Service issued her final decision on NSP's CIP program on August 13, 1991, which decision set the Company's CIP test year expenditures at $16,509,671. The incentive mechanism, when applied to the Commissioner's determination, increases the test year rate base by a net amount of $2,166,000, including a $931,000 reduction in rate base to remove unamortized CIP expenditures which were part of the original filing.

181. NSP and the Department each recommend that the Commission use the approved 1991 Conservation Improvement Program budget as the basis for setting test year expense levels. In addition, the Company, DPS and OAG all recommend that the Commission incorporate NSP's CIP financial incentive, approved in Docket E-002/M-90-1159, in determining the Company's final revenue requirement. Applying this financial incentive to NSP's approved 1991 CIP expenditures ($16,509,671) results in a final revenue requirement for CIP expenditures of $6,647,948. It is appropriate to order recovery of this amount during the test year.

Proposals of Minnesotans for an Energy Efficient Economy (ME3)

182. Minnesotans for an Energy Efficient Economy (ME3) provided testimony recommending that the Commission require NSP to implement a "Demand Side Demonstration Initiative" and to increase funding for Demand Side Management (DSM) programs to an amount between two and five percent of NSP's gross operating revenues. ME3 argues that the CIP commitment proposed by other parties in this case, which is just over one percent of the Company's gross operating revenues, is too low. ME3's proposed program would provide actual conservation improvements to a

variety of customer groups and would gather information about energy conservation potential among these groups.

ME3 recommends denial of this rate increase request in its entirety unless: (1) NSP is ordered to adopt methodology for evaluating the cost effectiveness of specific CIP programs placing primary emphasis on a societal cost test in assessing the benefits and costs society will experience as a

result of implementation of particular CIP programs or a particular overall demand-side management plan; (2) NSP is ordered to reduce the demand for electrical energy in its service territory at least two percent per year; and (3) the PUC implements ME3's proposed Demand-Side Demonstration Initiative.

183. ME3's proposals, while thoughtful and provocative, are appropriate for consideration as part of a Conservation Improvement Program docket before the Minnesota Department of Public Service, and are found not to be appropriate for consideration in this proceeding at this time. Minn. Stat. 216B.241 places the authority for approving CIP programs with the Commissioner of the Department of Public Service. ME3 did not participate in the recent CIP process and should not be allowed to use the current rate case proceeding to bring forward CIP programs. It may file its proposals with the Department as provided in Minn. Rules pt. 7690.1400. It is inappropriate to deny any rate increase to NSP because of non-compliance with ME3's proposals.

Conservation Cost Recovery

184. In Docket E-002/CI-88-684, the PUC initiated an investigation into the costs included in NSP's conservation cost recovery account ("Tracker"). As a result of that investigation, the Commission disallowed without prejudice approximately $1.2 million in program costs, administrative expenses and carrying charges because of concerns over the implementation of certain programs without or prior to Commission approval. In its Order, the PUC indicated that NSP could request recovery of these expenses in its next general rate case. NSP requested recovery of these deferred CIP expenses in this proceeding. The Company provided additional information concerning these expenditures and, since the PUC investigation, it has worked with both DPS and PUC staff to establish better communications regarding new programs and additions to CIP budgets. These actions should help avoid future problems with the Tracker account.

185. The Company also proposes to recover other, pre-test year expenses of $2,993,282 in the Tracker account by deducting them from the refund in this case, or, if there is no refund of interim rates, to recover them prospectively. NSP and the DPS agree that it would be preferable to recover the Tracker balance from the interim rate refund, if any, since it "trues-up" the

Tracker balance immediately. The Department also believes that NSP's explanation for incurring the previously-disputed CIP expenditures and NSP's method of accounting for them is reasonable. NSP and the DPS recommend recovery of the total amount of previously-denied and pre-test year CIP expenses, totaling $4,235,863, in the Tracker account from the Interim Rate refund, if any. In the alternative, if the Company makes no Interim Rate refund, these expenses should be amortized over a two-year period and recovered through base rates. The Administrative Law Judge finds the proposals to recover both CIP balances, and the proposed means of recovery (through the Interim Rate refund, if any) to be reasonable. It is further reasonable and appropriate that these expenses should be amortized over a two-year period and recovered through base rates if there is no Interim Rate refund or if the gross amount refundable is insufficient to "true up" the account.

NRC Fees

186. In its rebuttal filing, the Company stated that its operating expenses should be reduced to incorporate the appropriate level of 1991 Nuclear Regulatory Commission (NRC) fees. The proposed adjustment reduces NSP's 1991 revenue requirements by approximately $1.1 million. The proposed adjustment is found to be appropriate because it recognizes the recent decision of the NRC.

Rate Case Expenses

187. NSP requests recovery of $617,000 in unamortized rate case expenses by placement of that amount in the rate base. The DPS recommends that NSP not be allowed to receive a return on unamortized rate case expenses and advocates removal of those expenses from the test year rate base.

188. NSP witness Hervey does not object to removal of unamortized rate case expenses from the Company's rate base if the Company is permitted to recover the total rate case expenses in the test year. NSP Ex. 16, p. 32. The DPS shares this view. It is found appropriate to remove $617,000 from NSP's test year rate base as filed originally and to allow recovery of rate case expenses during the test year. The adjustment to the rate base from NSP's current position is $245,000, because the Company already removed certain rate expenses from rate base at an earlier stage of the proceedings, which removal is built into its final request.

Cogeneration Litigation Expenses

189. NSP was ordered by the PUC to reimburse the Rosemount

Cogeneration Joint Venture (Biosyn) for its litigation costs in a cogeneration dispute resolution proceeding before the PUC (Docket E-002/CG-88-491). Under Minn. Stat. 216B.164, subd. 5, and pursuant to the Order in that docket, Biosyn is entitled to recover for its costs, disbursements and attorney's fees.

190. The Commission's Order in Docket E-002/CG-88-491 specifically found that:

> NSP's conduct . . . cannot reasonably be interpreted as bad faith. NSP sought information and clarification of Biosyn's plans. NSP's need to plan for both the availability of the power and the construction of interconnection facilities to responsibly manage its electric power system required the information and clarification of plans. NSP's conduct reflects responsible management oversight, and cannot reasonably be interpreted to reach a threshold of bad faith . . . ."

The cogeneration litigation expenses incurred in the Biosyn matter arose from the normal course of utility business. NSP's proposal to recover the Biosyn litigation expense over a two-year period is reasonable. The DPS's argument that NSP could have avoided the litigation by simply honoring a valid contract over-simplifies a complex matter in which NSP took reasonable decisions on behalf of its ratepayers, who ultimately pay co-generators' fees.

MEC's argument that NSP's liability for attorney fees, etc., for the litigation constitutes a "penalty" that ratepayers should not bear is misplaced.

191. The DPS argues that ratepayers should not bear the cost for Biosyn's attorney fees. DPS recommends reduction in test year expenses by $175,428 and a decrease in the test year rate base of $262,000. As noted above, the Judge agrees with NSP on this issue.

192. The Department also advocates removal of $304,954 in other litigation expenses for the test year, these being NSP's expected 1991 legal costs to defend itself against an antitrust and RICO action filed by Biosyn and others. Regarding the Racketeer Influenced Corrupt Organizations (RICO) action, DPS argues that the facts of that case are similar to those before the PUC in Docket P-421/GR-79-388, where Northwestern Bell sought expenses related to the defense of an antitrust suit. In that case, the Commission held that litigation costs did not relate directly to the furnishing of telephone service and that the defense of utility property is the responsibility of shareholders and not ratepayers. The Department argues further that since RICO violations expose a defendant to both civil and criminal penalties, the defense of those actions are the responsibility of the shareholders.

193. Absent a showing in the record of the relative merits of the RICO action brought against NSP, the Company's petition to recover anticipated 1991 legal expenses in connection with defending itself in that action should be dismissed without prejudice. The Company is correct in its general assertion that defense against litigation is a normal cost of doing business, a cost that ratepayers should anticipate having to bear. However, in the absence of any documentation allowing him to compare the relative merits of the litigation for which NSP seeks recovery, the Administrative Law Judge is unable to conclude that NSP has met its burden of proof on this issue.

Profits From Coal Transportation and Nuclear Fuel Exchanges

194. NSP's arrangement with Burlington Northern Railroad, which transports coal for NSP, allows the Company to transport coal for ratepayers and for others and provides volume discounts after certain quantities have been transported. NSP provides the University of Minnesota coal transportation services for a fee. In 1987, NSP began recording the profits for coal transportation services to others "below-the-line" (outside regulated operations), after negotiating its discount agreement with Burlington Northern. The DPS argues that an adjustment should be made to NSP's operating expenses to recognize these profits.

195. NSP earns nuclear fuel exchange revenues through a number of nuclear fuel transactions, including borrow/sell and buy/replace simultaneous transactions, swap/exchange transactions, and brokerage services to acquire nuclear fuel. Beginning in 1988, NSP entered into various exchange and swap transactions that did not involve nuclear fuel materials for its own nuclear plants at Monticello and Prairie Island. Since 1989, NSP has recorded all costs associated with these brokering transactions "below-the-line". The DPS maintains that NSP's operating revenues should be adjusted upward to account for profits in nuclear fuel exchanges.

196. DPS argues that NSP would not be in these profit-making activities without the ratepayers' needs for coal and nuclear generation. In addition, the DPS urges that it was inappropriate for NSP to record the profits in these two businesses "below-the-line" without prior PUC approval.

197. The appropriate criteria for determining whether an activity should be treated as a regulated activity and thus included in test year revenues and expenses are whether the activity is necessary for the provision of utility service and whether other businesses are providing or are capable of providing the same or similar service, NSP argues. If an activity or service is not necessary for the provision of utility

service and is available from other suppliers, it should be not be treated as a regulated activity or service.

198. NSP's transportation of coal for the University of Minnesota and its nuclear fuel exchange activities are not necessary for the provision of electric service to NSP's customers. Coal transportation services and nuclear fuel brokering services are available from sources other than NSP. The Administrative Law Judge agrees with NSP's argument on these issues.

199. It is inappropriate to include revenues from the transportation of coal for the University of Minnesota in test year revenues.

200. The Company has recognized revenues from the exchange of nuclear fuel and fuel-related services relating to its fuel requirements for the Monticello and Prairie Island nuclear plants in its test year revenue forecast. It is inappropriate to recognize revenues from the exchange of nuclear fuel and fuel-related services not needed for NSP's Monticello and Prairie Island nuclear plants in test year revenues.

Social, Meeting and Miscellaneous Expenses

201. During its financial investigation in this case, the DPS conducted a detailed review of a portion of NSP's operating expense budget. It reviewed each cost element within DOE line 16 and each expense within cost element MS16, which accounted for over $28.5 million, 38% of the total DOE line 16 budget. The Department's review identified one cost element within DOE line 16 and several specific expenses within MS16 that the Department considers inappropriate for recovery from ratepayers and for which it recommends removal from NSP's test year operating expenses.

In investigating cost element MS16, the Department requested detailed descriptions of each budgeted expense. Upon reviewing NSP's descriptions, the DPS found several budgeted items for which NSP's description gave no explanation or justification, but stated such things as "misc.", "meeting-related expenses" and "other misc. materials based on historical average". The DPS argues that because of such sketchy descriptions, the Company has not demonstrated that it will incur these expenses for the regulated utility business. In addition, NSP could not provide further evidence as to why the questioned expenses were justifiable.

NSP argues that it would be inappropriate to exclude these expenses from test year expenses because the DPS offered no evidence that the expenses are excessive or unnecessary. NSP did attempt to describe these miscellaneous and meeting expenses in more detail than originally provided to the Department in answers to information requests, by providing examples of such expenses. However, NSP has already established cost categories for the types of expenses described, such as "CANT", which exists for the meeting expense examples provided by the Company.

202. The Administrative Law Judge agrees with the Department on this issue -- for the miscellaneous and meeting expenses in question, the fundamental issue is auditability. For example, cost element MS16 is titled "Miscellaneous Other Expenses". That element appears within DOE line 16, "Other Expenses". Budgeting an item for "Miscellaneous Other Expenses" within a DOE line titled "Other Expenses" provides no information as to why NSP needs these funds or why ratepayers should supply them. The Department's proposal to exclude $321,626 in miscellaneous and meeting expenses from NSP's test year operating expense budget is reasonable.

203. In addition to reviewing MS16, DPS witness Michelle Layton reviewed every other cost element within DOE line 16, including cost element SOCL. NSP described cost element SOCL as follows:

> Social Employee/Other Expenses -- As part of the total compensation package, NSP provides one social event each year for their employees. This common business practice provides for recognition and improves team work.

DPS acknowledges that certain social expenses may be appropriate and does not challenge recovery of some of them. Because of the large variety of cost elements, the Department could not identify all of the budgeted 1991 social expenses. It maintains that for $261,157 located in cost element SOCL, NSP has not demonstrated that the funds provide benefits and productivity that outweigh their costs. Further, NSP's budget guidelines provide no guidance as to how those expenses should be budgeted, or the appropriate level of social expenses. Due to the inabiity to audit the appropriateness of $261,157 of NSP's proposed social expenses, the Administrative Law Judge agrees with the DPS that it is appropriate to exclude that amount from test year expenses.

Electric Sales (Marketing) Programs

204. The DPS recommended that expenses associated with three of NSP's electric sales programs -- electric cooking, snow-melting and infrared heating -- be disallowed from rates. For such programs to be recovered, the PUC has consistently required them to pass cost-effectiveness analysis. In its decision in Docket E-002/GR-85-558, the Commission stated that a quantitative cost-benefit must be demonstrated for traditional marketing programs designed to increase customer demand.

205. The Department conducted a long-run cost effectiveness analysis of NSP's marketing programs, and ascertained that NSP's electric cooking, snow-melting and infrared heating projects,

totaling $109,400, failed that analysis. NSP urges a less stringent standard than that applied in the Department's analysis, which held the programs in question accountable for the long-run costs they will impose on NSP's system, including marginal peak capacity costs. The Administrative Law Judge agrees with the DPS's approach that the cost effectiveness analysis performed on electric cooking, snow-melting and infrared heating programs was proper and that those projects would be inappropriate for ratepayers to fund in this case.

Load Management Promotion Program

206.   In its February 6, 1990 Order establishing a Conservation Improvement Program, the PUC directed NSP to submit testimony on whether load management promotion program expenses are properly classified as Conservation Improvement Programs (CIPs) and on the reasonableness of NSP's proposed budget items for load management promotion. The testimony of NSP witness James Gamble that the Company's load managment program is properly classified as CIP and the level of expenses he sponsors for that program is reasonable in relation to NSP's load management activities were not challenged by any party to this proceeding. Load management rates encourage customers to reduce energy consumption during times of peak system load, which activity is properly considered one that "turns off or varies the delivery of energy" within the meaning of Minn. Stat.   216B.241. That statute defines energy conservation improvement as including any device, method or material that increases the efficiency in the use of electricity or natural gas, including systems to turn off or vary the delivery of energy.

The Company's Load Management Promotion Program is properly included in CIP and the requested budget for that program is reasonable.

Test Year Sales Forecast

207.   No Intervenor challenged NSP's test year sales forecast. The DPS forecasted lower total sales for NSP as a whole than did the Company. Therefore, the Department's analysis confirms that NSP has not understated its test year sales. It is reasonable and appropriate to adopt NSP's sales forecast, as filed in its original testimony.

Inventory Adjustment

208.   MEC proposes to reduce plant inventory by $10 million because, it contends, NSP has projected that level of inventory reduction at its Maple Grove facility. MEC's conclusion does not follow from the record. MEC interpreted the minutes of an August 15, 1990 staff meeting, where the feasibility of a $10 million

reduction in Company-wide plant inventory was debated, as the projection of that level of reduction during 1991 for NSP's Maple Grove facility.

MEC's contention is rebutted by NSP witness Matczynski, who testified that the suggestion was preliminary only for a possible reduction that could not be accomplished instantly, but was to be considered for accomplishment over a five-year period.

209. NSP has determined that it will not be able to achieve any part of the inventory reduction discussed at the August 1990 meeting. NSP's test year filing had already granted ratepayers the benefit of a $6.6 million reduction, even though NSP will not be able to actually achieve that reduction during 1991. The test year reduction of 11% in inventory, which the Company will not actually achieve, is much smaller than the recommended adjustment by MEC (which would be an additional reduction of 19%). For NSP to actually reduce its inventories by 28% would be imprudent since any forced shutdown of a plant due to lack of inventory, even for a few days, would cost far more than the

amount saved by reducing that inventory. MEC's recommended adjustment is inappropriate and should be rejected.

Cyprus Minerals

210. NSP has included costs of $2,226,000 in its test year cost of service study related to the purchase of power from Cyprus Minerals, under a Public Utilities Regulatory Policies Act (PURPA) agreement. MEC contends that the costs related to Cyprus Minerals proposed for recovery in the test year are speculative and should be excluded because NSP does not have a signed contract with Cyprus and the PUC has not approved any contract between NSP and Cyprus.

211. Subsequent to the close of the evidentiary hearing, NSP and Cyprus Silver Bay Power Company signed a formal Power Purchase Agreement and have filed it for approval by the Commission (Docket E-002/CG-91-524). It is appropriate to take official notice of that Agreement. Pursuant to that Agreement, Cyprus was to commence delivery of power and energy to NSP on July 1, 1991. The Company's proposal to include the cost of purchasing power from Cyprus is reasonable and is appropriate for inclusion in test year expenses. It is noted that the Commission is scheduled to meet and consider the appropriateness of the contract in question during the pendency of this rate case. If the Commission rules on the appropriateness of the contract before December 2, 1991 (when the decision in this Docket is due), it is appropriate to adjust NSP's test year expenses and revenue deficiency accordingly.

Wheeling Revenue Credits

212. MEC argues that NSP has not recognized the appropriate level of revenue credits for transmission revenues that it will receive during the test year. Specifically, NSP has not recognized enough credit for the Wisconsin Public Power, Inc. (WPPI) contract and has recognized no credits under the generic tariff filed by NSP and the Federal Energy Regulatory Commission (FERC).

213. The WPPI contract is a 30-year agreement for wheeling services for which NSP has reflected only two months of revenues in the test year. The Company has projected revenues for 1991 at $251,284 per month. MEC witness Derick Dahlen recommends that NSP recognize WPPI revenue credit for all of 1991, which treatment would best reflect the revenues NSP will receive for the period for which rates are being set. Dahlen's recommendation in this regard would reduce NSP's revenue requirement by $1,762,868. Dahlen recommends further that because NSP has recognized no revenue credits for its FERC generic wheeling tariff, and because the Company will have revenues from that tariff in the future, it should recognize those revenues in its rates. No specific dollar adjustment is recommended.

214. NSP's wheeling service under the agreement with WPPI will not begin until November 1, 1991. MEC's proposal to recognize a level of test year revenues assumes that the wheeling contract had been in effect for the full 12 months of 1991, which assumption is contrary to the record evidence. Such imputed revenues are inappropriate for inclusion in test year revenues.

It is also inappropriate to adjust test year revenues for wheeling revenues received under a generic tariff for the provision of services the Company filed with the Federal Energy Regulatory Commission. That tariff has not yet been approved by FERC and no customers have been identified who will take service under the generic tariff. Absent such information, and absent any evidence that the Company will receive revenues pursuant to that tariff during the test year, any adjustment in its filing to reflect such revenues is premature.

Nuclear Decommissioning Funds

215. NSP has decided to invest in debt instruments with maturities of five years for its external-qualified nuclear decommissioning fund. MEC challenges that decision, charging that NSP has no reasonable justification to choose investing in short-term maturity bonds to the exclusion of higher yield long-term maturity bonds. MEC witness Derick Dahlen testified that NSP sacrifices two percentage points when compared to

investing in bonds with a 20-year maturity. As a result of this allegedly imprudent investment strategy, ratepayers will be required to make up over $84 million in avoidable lost earnings during that 20-year period, MEC contends. It recommends an expense reduction of $4,200,000 in this rate case to adjust for imprudent investments made to fund future nuclear decommissioning.

216. NSP's nuclear decommissioning cost projections and proposed recovery procedures were approved by the PUC on February 25, 1991 (Docket E-002/D-90-185). The Company's decommissioning cost accrual included in this case is consistent with the Order in that docket. MEC's proposal to modify NSP's proposed investment strategy for external tax-qualified nuclear decommissioning funds is inappropriate.

217. MEC's criticism of NSP's investment strategy is misplaced. NSP has retained Delaware Investment Advisers to manage its external decommissioning fund and will use Delaware's "intermediate strategy" with average maturities ranging between seven and ten years. The Company's contention that such a strategy appropriately balances considerations of risk and return is reasonable. In addition, MEC's contention that there is a two percentage point differential between securities chosen by NSP and bonds with 20-year maturities is weakened by the fact that the two percentage point differential point is historical, not current, the comparison is of 20-year maturities to five-year (not seven to ten-year) maturities, and does not account for the greater risk of 20-year maturities.

Advertising Expense/Depreciation Expense for Personal Computers

218. On May 13, 1991, NSP filed a Motion to Update Filing in this matter, seeking admission to the record of data and information involving two errors in its initial filing, which, had the items been included in the Company's initial filing, would have added to the rate increase request by $5,672,832. The errors involved a mistake in categorization of $1,853,832 in administrative and general expenses as non-recoverable advertising expenses and a failure to expense the depreciation of the Company's personal computers.

219. In an Order issued June 17, 1991, the Administrative Law Judge granted NSP's Motion and provided interested parties additional time for discovery and comment concerning these items. No party has challenged the reasonablenss of the items.

The Company has demonstrated good cause for inclusion of these expenses and no party is prejudiced thereby. The discrepancies in the Company's original filing were caused by oversight and human error.

The expenses will be incurred during the test year and are ordinary expenses associated with the provision of electric service. Inclusion of these items in test year expenses is found to be reasonable and appropriate.

220. During the briefing period, the DPS renewed its objection to the inclusion in the record of any evidence of the advertising expense adjustment and depreciation expense for personal computers reflected in NSP's Motion to Update Filing. The Department argues that the Commission's Order Affirming Decision of the Administrative Law Judge issued June 26, 1991, improperly shifts the burden to the Intervenors to show either unfairness or inaccuracy in order to prevent such additional expenses from coming into the record. The Department urges the Commission to reconsider and determine on its own whether the Administrative Law Judge ruled properly that NSP demonstrated good cause to introduce new affirmative matter at the time it sought such introduction. The Administrative Law Judge takes no position on this issue beyond that expressed in his June 17, 1991 Order Granting NSP's Motion.

The Administrative Law Judge has considered again the objection of the DPS to inclusion of the items, and that objection is overruled. DPS's briefing argument, which in essence constitutes a Motion for Reconsideration, is now squarely before the Commission.

Stipulation on Deferred Expenses

221. One of the Commission's concerns in dismissing NSP's last rate filing was that certain expenses were "loaded" into the test year that more properly were assignable to prior years. At page 28 of its Order in Docket 89-865, the Commission noted:

> The test year concept rests on the notion that the normal and ongoing costs of operating a utility can be determined with reasonable accuracy and built into rates. Rates are not set on the basis of extraordinary expenses, or on the basis of a need to "catch up" from having delayed normal and ongoing expenses in the past.

Following the denial of its rate increase request in 1990, NSP set a goal of reducing controllable operating expenditures by $50 million in order to maintain earnings and achieve a targeted earnings-per-share figure. The Company actually achieved expense reductions of roughly $38 million last year. The fact that such reductions could be made raised the concern among Intervenors that NSP deferred expenses improperly from 1990 into 1991, thereby inflating the Company's true needs for the test year and future years.

222. During the course of investigation of this filing, the

DPS has issued a series of information requests attempting to explore the issue of deferred expenses. The process of requesting information on deferred expenses and NSP's responding to those requests was not completed by the close of the evidentiary hearing, so counsel for the Department specifically reserved the right to offer NSP's response to DPS Information Request No. 50, along with an appropriate suggested deferral adjustment for the record, and the Administrative Law Judge ruled to allow such a process.

223. On July 19, 1991, NSP filed its Answer to Department Information Request No. 50 with the DPS. After reviewing that response and NSP's original fiing, the Department, together with OAG and MEC, identified certain other 1990 expense reductions which may have increased the test year budget. NSP agreed to recognize an adjustment for these items as well and entered into a Stipulation on Deferred Expenses with DPS, OAG and MEC on August 2, 1991. That Stipulation, filed with the Administrative Law Judge on the same day, identifies $4,443,400 in carry-over expenses in the 1991 test year budget on a Minnesota company basis. A follow-up letter, filed on August 14, 1991, provides the Minnesota electric jurisdictional breakdown for these deferred items. The Stipulation thus results in a reduction of NSP's revenue requirements of $3,257,900.

224. The Stipulation on Deferred Expenses provides the kind of accurate, detailed information on carry-over expenses the Commission was concerned with identifying in Docket E-002/GR-89-865. The Stipulation is supported by the exhibits attached thereto and the record of this proceeding, and the Administrative Law Judge hereby admits it to the record as a piece of evidence to be considered by the Commission in determining adjustments to NSP's test year revenue requirements. It is appropriate to adopt the August 2, 1991 Stipulation on Deferred Expenses in order to aid in the elimination of carryover expenses from the test year budget.

225. On August 9, 1991, North Star Steel filed a Limited Objection to Stipulation on Deferred Expenses. North Star's objection asserts that the Stipulation and supporting documents should be admitted only for purposes of impeachment of NSP's testimony and to show that NSP carried over at least $4.4 million in expenses from 1990 into the 1991 test year.

226. In response to North Star's objection, the parties to the Stipulation agreed that while the evidence could certainly be used for impeachment purposes, its evidentiary value should also be recognized in support of the Stipulation. It is appropriate to admit the Stipulation and supporting documents as proof of the need for an adjustment of at least $3,257,900 to NSP's revenue requirement. It is also proper to view the evidence as an admission by NSP that such an adjustment is appropriate. While admitting the evidence as proof for that purpose, it is also true that the Stipulation may be considered for impeachment purposes or for any other purpose the Commission may use to apply it properly.

227. North Star's objection is to an admission of the Stipulation to show that the deferred expenses from 1990 to 1991 contained in the test year are limited to $4.4 million. North Star proposes no specific other adjustment for carryover expenses but relies on a broad inflation-based adjustment to include both deferred expenses and any other item which may be inappropriate for recovery from ratepayers, as discussed above. As noted in earlier Findings, North Star's proposed adjustment is inappropriate and should not be adopted.

To the extent that North Star filed its Limited Objection for the purpose of providing further support for its inflation-based adjustment to NSP's overall expenses, the Limited Objection is overruled. To the extent that North Star's Limited Objection is confined specifically to use of the Stipulation to prove that NSP's deferred expenses are limited to $4.4 million, that objection is sustained in part and overruled in part. Specifically, North Star's contention that any evidence that NSP's 1991 deferred expenses are limited to $4.4 million must come from elsewhere in the record than the Stipulation and supporting documents is overruled. The Stipulation and supporting documents can be used by the PUC to come to such a conclusion, or any other conclusion that the now-admitted evidence warrants. The part sustained by this ruling is that the rest of the record can still be used as a source of evidence to establish the existence of deferred expenses other than those noted in the Stipulation.

Incentive Compensation

228. MEC filed testimony in this proceeding recommending the removal of incentive compensation costs totaling $14,734,000 from NSP's test year revenue requirement. $13,300,000 reflects the Minnesota jurisdictional portion of test year incentive compensation payments, and the additional $1,434,000 reflects monies allocated for Pension Make-Up Incentive Compensation. MEC argued that the PUC should reject NSP's request and disallow the $14.734 million adjustment because the Company's incentive compensation program imposes unnecessary and unreasonable costs on ratepayers.

229. MEC maintains that the most offensive feature of NSP's incentive compensation program is that no such compensation will be paid to anyone unless the total company earnings per share exceed a certain level. In addition, MEC objects because the amounts included in the test year budget for incentive compensation are allegedly speculative. MEC bases this contention on the fact that NSP will not know what amount, if any, it will pay out for incentive compensation until its 1991 results are known. MEC argues that unless 1991 earnings per share are $2.75 or more, NSP will pay out nothing in incentive compensation and the budgeted amount used to set rates in this

case would be available for general use by the Company.

230. For years 1988 through 1990, NSP paid out to its employees 98.5% of the amount budgeted for incentive plan costs. This history indicates that NSP's target incentive plan payment amount has been accurate.

231. MEC argues further that NSP's incentive compensation program is unnecessary for the provision of electric service, provides excessive compensation, and that NSP, by presenting witnesses who have part of their compensation contingent upon the PUC's decision in this case, has violated the Minnesota Ethics in Government Law (Minn. Stat. Ch. 10A).

232. NSP's incentive compensation plans are a component in the Company's comprehensive compensation system. No requirement exists under any statute or by Commission rule or practice for prior PUC approval of incentive compensation plans or compensation systems.

The Company's incentive compensation plans are in the public interest and benefit ratepayers, in that they encourage improved productivity and reduced

costs. The incentive compensation plan does not, either in general terms or by reference to individual performance goals, constitute "the employment of a lobbyist for compensation which is dependent upon the result or outcome of any legislative or administrative action" within the meaning of Minn. Stat. 10A.06.

233. Services performed by NSP employees who are eligible for incentive compensation are reasonable and necessary to the provision of electric utility service and the total compensation of those employees, including incentive compensation, is not excessive or unreasonable.

The fact that NSP's incentive compensation plan is designed to put some portion of salary at risk of not being received unless corporate and individual goals are met, and that one of the corporate goals is that the Company earn its authorized rate of return, is not against public policy.

It is appropriate to adopt the Company's proposals for incentive compensation without an adjustment for such compensation in the revenue requirement, except as noted in the four subsequent Findings.

234. On August 21, 1991, NSP filed a Motion for Leave to Reopen the Record to Offer Late Filed Exhibit. In its Motion, the Company stated that it had come to NSP's attention that the Minnesota jurisdictional incentive compensation had been overstated by $1,973,701. NSP moved to allow this information to

be placed into the record and agreed to accept an adjustment to its revenue requirement in that amount to reflect the correction. The adjustment is necessary because the portion of incentive compensation set aside for bargaining-unit personnel had a four percent wage increase assumption built into it, whereas it should have reflected only a two percent raise in 1991.

235. On August 27, 1991, MEC filed a Motion for Sanctions relating to the NSP Motion. In its Motion, MEC asked that the PUC order that as a result of NSP's failure to disclose accurate information, NSP should be sanctioned pursuant to Rule 37.02(b) of the Rules of Civil Procedure with a ruling denying NSP any portion of incentive compensation for setting rates. If this Motion is granted, it would have the same effect as adopting MEC's original recommendation on that issue, a reduction in revenue requirement of $14,730,000.

236. A sanction under MRCP 37.02(b) would technically be appropriate only if NSP had failed to comply with an Order Compelling Discovery. Such is not the case at this stage in the proceedings. Rather, NSP has supplied discovery and offered testimony which was misleading and inaccurate, which inaccuracies it seeks to remedy with the filing of its Motion to Reopen. NSP's Motion constitutes an admission that its revenue requirements should be reduced by $1,973,701 for purposes of setting rates in this case.

237. NSP's Motion for Leave to Reopen the Record to Offer Late Filed Exhibit is GRANTED. Its late-filed Exhibit adjusting the incentive compensation amount is admitted to the record. Minnesota Energy Consumers' Motion for Sanctions relating to NSP's Motion to Reopen is DENIED.

It is appropriate that an adjustment of $1,973,701 be made in the final revenue requirement to recognize a reduction in incentive compensation by that amount.

Discussion

After considering all of the Briefs, Proposed Findings and subsequent filings regarding MEC's Motion for Sanctions, the Administrative Law Judge has decided that the Company has met its burden of proof with respect to the incentive compensation issues raised by MEC and that MEC's Motion for Sanctions, which would reduce NSP's revenue requirement by $14,370,000, should be denied.

The Judge did not arrive at this position without giving careful thought to whether the Company's errors in presentation of its filing and testimony in this case, when taken together with the omissions underlying its Prehearing Motion to Update Filing and its entrance into a Stipulation on Deferred Expenses, should be sanctioned further. MEC argues that these actions, taken together, constitute a pattern of manipulation of the rate case process by the Company through its filing of an inaccurate and unreliable case. MEC states that the Company further misled Intervenors in discovery and during the hearings on both the subjects of deferrals and incentive compensation, and perpetuated those misrepresentations after the hearings with respect to the issue of incentive compensation. MEC urges the Commission to be concerned about what other misrepresentations might remain in the rate case filing because NSP may not have accurately presented its case, fully replied to discovery or offered testimony in a truthful fashion.

The Office of Attorney General states that it would prefer to see the issue of incentive compensation decided "upon its merits", which OAG alleges would require a reopening of the evidentiary hearing. Both the OAG and the DPS are deeply troubled by the reasons given in NSP's affidavits attached to its Reply to MEC's Motion for Sanctions, which affidavits imply that NSP personnel were, at the least, negligent or incompetent in failing to recognize that the dollar figures for incentive compensation portions to be awarded to bargaining unit employees assumed a four percent raise at a time when the Company knew, or should have known, that the raise was only two percent. MEC argues that affidavits showing when certain NSP officials learned of errors having effects on the rate filing, and when they finally came to a realization of those effects, simply cannot be believed. Based on the record before him, the Administrative Law Judge has decided that NSP's incorrect testimony resulted from human error attributable to oversight and incompetence.

The affidavits filed in support of NSP's Motion to Reopen impeach the prefiled testimony of NSP witness Hewitt. Hewitt's allegation that he learned of the error in early July but did not realize the error affected the rate case filing and his testimony therein is certainly suspect. An issue exists whether, as a matter of law, Hewitt's testimony then is impeached to the point that his entire testimony (NSP Exhibit 36) should be disregarded and NSP held not to have met its burden of proof on the entire issue of incentive compensation. The Administrative Law Judge has decided not to accord the impeachment of Hewitt that much weight. Specifically, Hewitt's testimony at page 17 of Exhibit 36 to the effect that 1991 test year costs are at target incentive levels should be allowed to stand. The Administrative Law Judge so concludes because there is no specific challenge to that portion of testimony or to the other, corroborating evidence that for the years 1988 through 1990, total budgeted incentive plan costs were 19.7 million, and the amount actually paid was 19.4 million, which is only 1.5% under budget over the three-year historical period.

Mr. Hewitt was informed during the first week of July that a discrepancy existed, due to a budget error, between the second quarter 1991 forecast of incentive compensation and the budgeted amount and that the budget continued to reflect a four percent assumption for bargaining unit employees. Hewitt's affidavit filed as part of NSP's Motion states he did not realize this would have any implications for the rate case and considered that such information would not be relevant until the discussions of the 1992 budget process. As noted above, the Administrative Law Judge agrees with the Intervenors who argue that the foregoing statement by Mr. Hewitt is troubling because he sponsored the dollar amounts on this subject in the rate filing. While the affidavit impeaches the balance of the testimony Hewitt offered in this proceeding, the Administrative Law Judge believes there is sufficient competent evidence corroborating his testimony that test year costs will equal target incentive levels.

Exhibit 7 of NSP Exhibit 36 indicates that of the $19.7 million budgeted for incentive plan costs for 1988-1990, $19.4 million was paid. Hewitt's written testimony corroborates the figures in Exhibit 7, but Exhibit 7 stands alone as independent evidence that the Company's incentive payment projections were accurate. It is reasonable to expect the same accuracy for the period covered by the test year. The discrepancy leading to NSP's Motion to Reopen is attributable to an error in iteration regarding the specific figure for bargaining-unit employees. While the filing states the figure represents a two-percent raise, the number itself still reflected a four-percent assumption. To overlook that discrepancy was an error that misleads the reader. NSP's late-filed exhibit corrects the error. He is not persuaded that this problem, taken together with the errors uncovered in May and the subsequent admissions on deferred expenses warrant total exclusion from expenses of all incentive compensation amounts. MEC's Motion for Sanctions should be denied.

Refuse Derived Fuel (RDF) -- Red Wing and Wilmarth

238. Mankato Citizens Concerned with Preserving Environmental Quality (MCCPEQ) proposed the removal of NSP's Red Wing and Wilmarth generating plants from rate base. MCCPEQ introduced testimony alleging that NSP invested in pollution control devices at Wilmarth, which investment was not in the best interests of ratepayers, who allegedly would have realized more savings had the plant simply been retired. MCCPEQ further alleges that continued operation of the Wilmarth and Red Wing plants is not in the best interest of ratepayers.

239. In response, NSP argues that MCCPEQ bases its analysis on preliminary studies and incomplete information. The Company introduced evidence demonstrating that NSP's investment in pollution control equipment at Wilmarth was necessary and economically justifiable. NSP contends that it further demonstrated that ratepayers are not adversely affected by continued operation of the Red Wing and Wilmarth plants. The Company urges rejection of MCCPEQ's proposal to remove the investment in the Red Wing and Wilmarth plants from rate base. It argues further that MCCPEQ's posture in this case is inconsistent because it was only at the urging of MCCPEQ that the

Minnesota Pollution Control Agency required NSP to install the baghouse and scrubber facilities MCCPEQ now argues were imprudent investments.

240. MCCPEQ argues that an analysis by Mr. Grover of NSP concluded that continued operation of NSP's Wilmarth plant using RDF under status quo conditions with the addition of pollution control equipment would result in a net $29.7 million additional cost to NSP's ratepayers.

NSP replied that Grover's analysis was not an accurate measurement of the economic impact of Wilmarth today because actions were subsequently taken that were not considered in his analysis. Among those actions are implementation of cost-saving measures at the plants and incentive payments to NSP's regulated side from its non-regulated solid waste processing business. The payments compensate the regulated utility for burning refuse-derived fuel (RDF). The Company maintains these actions achieve essentially the same cost savings for ratepayers as estimated for the retirement option in Mr. Grover's study.

241. NSP witness Matczynski testified none of the cost-saving measures resulted in any loss of efficiency at the plants and that had those savings not taken place the incentive payments would have been higher in order to equal the amount of savings and thus keep ratepayers financially indifferent.

242. The OAG contends that NSP is unable to explain why it should not and could not have engaged in the cost saving measures at its RDF-burning generating units irrespective of the economics of RDF operations. The OAG contends that since NSP has a duty to run its power plants as efficiently as possible at all times, the ratepayers received no special benefit by NSP having engaged in cost savings at Wilmarth and Red Wing. Therefore, the cost savings cannot be considered as a special or extra benefit of the RDF program.

The OAG argues further that since it is NSP's contention that cost savings plus incentives will make ratepayers financially indifferent, and because the cost savings cannot be counted as a benefit of the RDF program, an adjustment should be made to impute additional incentive payments so as to make ratepayers truly financially indifferent to the RDF operations. They suggest an additional imputation of $1,035,000 in revenues during the test year.

243. The DPS suggests that, since MCCPEQ provided extensive evidence of what it believes to be an ongoing subsidy of NSP's unregulated RDF business by electric ratepayers, and because a full record on that issue was not possible in a rate case proceeding examining only one calendar year, that the resolution of this issue requires a fuller record. The Department suggests

that the Commission should exercise its investigatory powers under Minn. Stat. 216B.17 and open an investigation to determine whether ratepayers have subsidized NSP's unregulated RDF business.

244. It is appropriate to deny the proposal by MCCPEQ to remove the Red Wing and Wilmarth generating plants from the rate base for the purposes of test year 1991. It would be appropriate for the Commission to exercise its investigatory powers under Minn. Stat. 216B.17 and open an investigation to determine whether ratepayers have subsidized NSP's RDF business. To aid in that investigation, and serve as a possible starting point, it is appropriate to bind over to the record of that investigatory proceeding all testimony and exhibits pertaining to refuse derived fuel issues marshaled in the record of this proceeding.

245. The Administrative Law Judge finds that it would be improper to adopt the OAG's proposal to impute an additional $1.035 million in revenues during the test year as additional incentive payments to make ratepayers truly financially indifferent to the further conduct of RDF operations. NSP's identification of total savings of $56.1 million under continued operation of Red Wing and Wilmarth would offset both the alleged $30 million cost savings from retirement, and the present value of production cost savings at Red Wing and Wilmarth ($15.2 million, the sum of $9.3 million at Red Wing and $5.9 million at Wilmarth). Therefore, there is no basis to impute additional hypothetical revenues even if the OAG's premise that cost savings cannot be counted as a benefit of the RDF program is assumed.

Discussion

MCCPEQ intervened in this proceeding to address what it believes to be an ongoing subsidy of NSP's private venture into the Municipal Solid Waste/Refuse Derived Fuel (MSW/RDF) market by its electric utility ratepayers. The extent of the alleged subsidy costs ratepayers many millions of dollars in increased rates annually, MCCPEQ maintains.

While MCCPEQ believes this subsidy has been ongoing since the start of NSP's entry in the market, it did not seek to expand this proceeding into an inquiry over whether any adjustments are appropriate for years prior to the test year. MCCPEQ makes a specific recommendation that the Commission exercise its authority under Minn. Stat. 216B.17 to open a separate proceeding to investigate the extent of any historical subsidy of NSP's unregulated venture in the MSW/RDF business.

NSP's decision to enter the MSW/RDF business followed the passage of the Waste Management Act in 1980. The legislation mandated that by 1990, counties in the seven-county metropolitan area could no longer landfill MSW as the primary means of disposal, thereby requiring new methods for disposal of municipal solid waste. NSP subsequently decided to enter that market by providing facilities that convert MSW into refuse derived fuel (RDF), which in turn is burned for the production of electric power at plants retrofitted to use RDF as a substitute for coal.

The Company actively engaged in the MSW/RDF business first by winning a bid for the MSW of Washington and Ramsey Counties, which it processes into refuse derived fuel at a processing facility located in Newport, Minnesota. The RDF is then shipped and burned in the Red Wing and Wilmarth (Mankato) generating stations, which have been specially modified to enable them to burn RDF.

NSP initially approached the Public Utilities Commission with a petition for an Order finding that the investments and expenses for RDF facilities should be considered regulated utility property for ratesetting purposes. The Commission issued an advisory opinion stating that it was premature at that time to make a determination as to whether RDF-related facilities should be in rate base. A decision regarding what portions, if any, of the MSW/RDF business should be regulated or not was deferred until the Company's next general rate case. In its decision in Docket E-002/GR-85-558, the PUC determined to split NSP's MSW/RDF business into a regulated "combustion" side and an unregulated "processing" side. The Company filed testimony in that

case stating that the cost paid by ratepayers for RDF would result in no greater fuel cost than if NSP did not burn RDF and that the production cost of the modified Red Wing and Wilmarth plants running on RDF would be comparable to that at NSP's cheapest coal-fired generation currently operating.

The Company's analysis in that rate case featured a comparison of the cost of power from Red Wing and Wilmarth burning RDF with the cost of power from a PURPA Qualifying Facility (QF) based on NSP's then-effective PURPA rate. The study assumed a 20-year life extension for Red Wing and Wilmarth due to the retrofitting and total estimated capital expenditures of $24,192,000. The benefit-to-cost ratio in NSP's study was .98, meaning that the benefit to ratepayers was slightly below the cost.

MCCPEQ, using updated actual figures to demonstrate what it contends are the uneconomic consequences to ratepayers of NSP's decision to burn RDF as a fuel, states that the actual capital expenditures to date on Red Wing and Wilmarth total over $41 million, and that these expenses do not include an additional $6 million which will most likely be spent for added pollution control equipment at Red Wing. Based on a comparison of the numbers, it is obvious to MCCPEQ that the cost to ratepayers is well in excess of the benefits derived therefrom.

MCCPEQ contends further that since NSP used, as a "proxy" cost of fuel for RDF, the same rate as the PURPA QF (qualifying facility) fuel cost (which was based on the coal cost at the

Company's Sherco 3 plant), the fuel cost of RDF would be equal to the fuel cost of a PURPA QF. Savings to ratepayers as compared to purchasing power from a PURPA QF would allegedly come from the difference in capacity costs. However, contrary to NSP's conclusion that the capacity costs for the Red Wing/Wilmarth conversions would be only $101 per kilowatt, those costs (based on the actual capital cost of conversion of over $41 million) actually have amounted to $172 per kilowatt as compared to the $155 per kilowatt for a PURPA QF. MCCPEQ also stresses the fact that a PURPA QF is entitled to the higher capacity rate of $155 per kilowatt only if it operates at a 70% capacity rate or greater whereas, in the years since its conversion, Wilmarth has only operated at most at a 35% capacity factor.

MCCPEQ also introduced evidence indicating that production costs at Red Wing and Wilmarth, compared to production costs at NSP's base load plants, was extremely high. MCCPEC contends that Red Wing's average generation cost is over four-and-a-half times that at Sherco, while Wilmarth's is approximately eight times as much.

In 1989, when NSP was faced with the prospect of having to upgrade the pollution control equipment at Wilmarth, specifically adding a bag house and scrubber, the Company conducted a study (the Grover study) which considered various options to determine the relative economic impact to ratepayers. MCCPEQ contends the Grover study shows that NSP's ratepayers would save $30 million if Wilmarth were simply retired rather than continuing to burn RDF at the plant. MCCPEQ contends that NSP decided to continue operating at Wilmarth and to spend the capital necessary to install the bag house and scrubber assets because if Wilmarth were retired, the Company would run a high risk of being unable to burn all of the RDF it must process under contracts with Washington and Ramsey Counties. Grover estimated the potential contract penalty to the Company to be in the range of $16.2 million to $35.6 million. MCCPEQ contends further that it is a reasonable assumption that a similar

study conducted by the Company on the Red Wing plant would show similar results because the economics of both plants are very similar. MCCPEQ concludes that NSP's entry into the RDF business with its private venture puts NSP into a conflict of interest position vis-a-vis its ratepayers.

Furthermore, MCCPEQ contends that the Grover study underestimates capital expenditures in connection with pollution control equipment by over $4 million at Wilmarth. Approximately half that difference is an underestimation of costs for the bag house and scrubber, and the rest is largely attributable to an underestimation by a factor of nearly two-to-one in costs assumed for an ash landfill. In response to MCCPEQ's concerns, NSP witness Craig Mataczynski testified that, based upon the Grover analysis conducted in 1989, he did a further analysis to determine if NSP's continued involvement in the MSW/RDF business is warranted. Mataczynski testified that NSP took actions not contemplated in the Grover analysis which leave ratepayers in a better position than if the plants were retired. NSP purportedly enhanced the quality and increased the volume of RDF delivered to Red Wing and Wilmarth, implemented a series of cost saving measures at Red Wing and Wilmarth and its RDF business provides an incentive payment to the regulated utility for combustion of RDF. Mataczynski ascribed quantitative benefits to each of the measures, totaling $56.1 million, which when compared to the estimates in the Grover study, leads to a conclusion that ratepayers will be made indifferent to the continued operation of Red Wing and Wilmarth.

MCCPEQ argues that Mataczynski's study and assumptions are incorrect, including his assumption of burning 374,000 tons of RDF at Red Wing and Wilmarth, which MCCPEQ contends cannot be achieved because of the limited ability of the Newport facility to process enough municipal solid waste to produce that amount of refuse derived fuel. In addition, the counties are facing new legislation requiring them to engage in large recycling and waste reduction programs rather than simply having their waste processed. Minn. Stat.   115A.551 was amended in 1991 to require metropolitan counties to recycle, by 1996, 45% (by weight) of their total solid waste generation.

In response, NSP contends that MCCPEQ's cost benefit analyses are flawed, and that its witness (Katy Wortel) was incompetent to testify. At the hearing, the Administrative Law Judge overruled NSP's objection to Ms. Wortel's testimony and allowed it all in for the purpose of aiding a decision on whether an investigation under Minn. Stat.   216.17 should be initiated.

NSP challenges MCCPEQ's implication that regulated-side employees were working for the RDF "processing" (unregulated) side without an appropriate allocation of their compensation. It attacks MCCPEQ's conclusion regarding capital investment at Red Wing and Wilmarth because MCCPEQ's analysis refers to the impact of additional investments in capacity today compared to the capacity costs calculated for a PURPA QF in 1985. The Company contends such an analysis is "piecemeal" and mismatches historical data with current data. The Company attacks MCCPEQ's quantitative analyses in several other respects for not using updated dollar amounts. In comparing costs at the RDF burning units with Sherco, the Company finds fault with MCCPEQ because it compares an aggregate cost for all three Sherco units rather than the most-recent Sherco 3 plant. In addition, using Sherco 3 for comparison purposes to the Mataczynski study is allegedly improper because that plant was already in service and its costs could not be avoided by the continued operation of Red Wing and Wilmarth.

NSP also contends that the 70% capacity factor assumed in

Mataczynski's analysis is achievable, that the proposed incentive payment is fair to ratepayers, and that there is no reason to depart radically from standard ratemaking principles or to remove from rate base generating units which are used and useful in the provision of electric services during the test year.

The Company contends further that no subsidy from the ratepayers to the non-regulated side could possibly have occurred. It alleges that none of the increased costs relied upon by MCCPEQ in its effort to prove the lesser benefit of Red Wing and Wilmarth have been recovered in rates because none were counted in a rate case test year or because any that may have been were included in Construction Work in Progress (CWIP) and were offset by the Allowance for Funds Used During Construction (AFUDC) credit to income. Therefore, no separate proceeding is necessary or justified.

The Company points out that until the Commission's final Order in this case (which will assumedly include the converted plants in rate base), NSP's Minnesota retail ratepayers will not have actually been required to pay in rates for any of the costs of converting the Red Wing and Wilmarth units. The conversions were not completed until 1988, and while initial conversion costs were included in construction work in progress in the 1985 rate case (Docket E-002/GR-85-558), those costs reflected only $4 million, which is clearly within the Company's $24 million assumption. Furthermore, those costs had no ratepayer impact because they were fully offset by the credit to income for the allowance for funds used during construction. As authority, NSP cites the Commission's June 2, 1986 Order in that Docket, at page 17:

> The Commission has determined that the AFUDC offset method used by NSP effectively eliminates a current return on long term CWIP.

As to the 1987 rate case, the Company contends that conversion costs would not have included the costs of adding the environmental enhancements at Wilmarth since those costs were not incurred until after the analysis performed by Mataczynski in 1989. The Company argues that if the PUC has concerns about the regulatory treatment of NSP's RDF operations, those concerns can be fully addressed within the context of this rate case and no separate investigation under another statutory authority is necessary.

The Company also contends that the Commission is barred from any investigation that would reverse prior Commission Orders. The Company contends that any disparity in costs envisioned by its 1985 studies and capital costs are caused in large part by the addition of pollution control equipment which, in 1985, could not reasonably be foreseen. Indeed, the Company accuses MCCPEQ of causing the Minnesota Pollution Control Agency to adopt permit limitations requiring installation of the equipment. The Company contends further that it has properly allocated employee time between its regulated and non-regulated sides.

NSP argues also that Minn. Stat. 216B.17 is too narrow in scope to allow an investigation of the type requested by MCCPEQ. The Administrative Law Judge does not agree with this contention of NSP. Subdivision 1 of section 216B.17 provides that the Commission may, on its own Motion, investigate any rates relating to the production of electricity that may in any respect be unreasonable. Under Subdivision 8, the PUC may initiate a

contested case or order a utility to initiate a rate case if the investigation does not resolve the matter.

Based upon all of the competing arguments noted above, it appears clear tha the Commission should consider an investigation under the authorizing statute. NSP acknowledges that conversion costs pertaining to Red Wing and Wilmarth may have been reflected in Plant in Service for rates approved in Docket GR-87-670 on June 2, 1988, so its allegation that ratepayers have not yet paid any conversion costs, supported only by an argument that the costs of adding environmental enhancements at Wilmarth did not occur until sometime after March 1989, is suspect. It is reasonable to conclude that these issues need further investigation in a separate docket confined to that purpose. Accordingly, the Administrative Law Judge has also recommended against removal of the two plants from rate base in this case.

UPA Purchases

246. NSP included in test year expenses the cost of purchasing electricity from United Power Association's (UPA) Elk River facility pursuant to a Power Purchase Agreement. MCCPEQ alleges that NSP negotiated an excessive capacity rate to benefit its RDF operations.

247. MCCPEQ's argument overlooks the fact that, while NSP may have agreed ultimately to a somewhat higher capacity rate, it secured a lower energy rate and pays a total cost for capacity and energy which is less than what NSP would have been required to pay any PURPA Qualifying Facility (QF) that might have obtained the Anoka County municipal solid waste (MSW) and turned it into energy for sale to NSP.

248. The Administrative Law Judge finds that the capacity and energy rates paid by NSP to UPA under its Power Purchase Agreement are reasonable and the costs of purchasing electricity from the UPA facility are appropriate for inclusion in NSP's test year expenses.

Discussion

MCCPEQ contends that any capacity payments made in 1991 between the contract rate of $116.00 per kilowatt per year and $77.00 per kilowatt per year (contained in an earlier agreement with UPA) be disallowed from test year expenses. That argument assumes that NSP could have obtained the power from UPA at the $77.00 capacity rate. In fact, the evidence shows that Anoka County's solid waste would have gone elsewhere if UPA had not raised the capacity rate, thus allowing a drop in the energy rate, enabling NSP to lower its bid to Anoka County for the purchase of MSW. It was appropriate for NSP to approach this transaction as it would that with a PURPA QF since any other successful bidder for Anoka County's MSW would compel NSP to purchase the electric output at NSP's PURPA rate. That purchase would have been obligatory on NSP's part, irrespective of whether NSP actually had a present need for the power. The fact that the capacity cost portion over the PURPA rate of $95.00 per kilowatt per year was funnelled to NSP's unregulated RDF "processing" business is immaterial. The record shows that the $19.00 per kilowatt differential was used to enable the unregulated entity to make a successful bid for Anoka County's MSW. Absent such a transaction, NSP's rate payers

would have been required to pay a higher total cost for purchase of power using the same waste because that power would be produced by a PURPA QF and NSP would have been compelled to purchase it.

Motion to Dismiss Minnesota Utility Investors

249. On July 10, 1991, MEC filed a Motion to Withdraw the Intervenor's Status of the Minnesota Utility Investors. In an accompanying Memorandum and Attached Documents, MEC established that Intervenor Minnesota Utility Investors (MUI) was given assistance by NSP personnel during its organizational stages in mid-1990, that a member of NSP's Law Department served as Secretary to the group, and that the Company distributed brochures for MUI in its October, 1990 dividend statement. From this, MEC argues that MUI is an "arm" of NSP.

250. In a letter replying to the Motion, filed with the Administrative Law Judge by MUI's President and CEO on July 19, 1991, MUI repeated the argument from its Petition to Intervene -- that it has approximately 8,000 members who own stock in one or more gas and electric companies operating in Minnesota, that MUI provides an independent voice through which utility investors (who are also ratepayers) may express themselves collectively about their interests, rights and concerns, and that as owners of utility companies, MUI members are interested in decisions that impact their investments.

251. MUI did not participate in the public or evidentiary hearings by way of oral or written testimony, nor did counsel or representatives of MUI examine or cross-examine any witnesses. MUI did not file briefs in this proceeding. MUI's remaining rights in this proceeding consist of a right to file exceptions

to the Findings, Conclusions and Recommendations of the Administrative Law Judge and a right to appeal the final decision of the Public Utilities Commission.

252. While MEC has established that MUI has received substantial assistance from NSP and its personnel during its period of organization, there is no indication in the record that MUI is not independent of NSP. That a group such as Minnesota Utility Investors received substantial assistance in setting up, including having its literature distributed in the dividend statements sent to shareholders in Minnesota's largest electric utility, is not inconsistent with its being independent of any particular utility which may bring rate requests before the Public Utilities Commission.

253. An organization that exists to advance the concerns of utility shareholders may decide to file exceptions or appeals from decisions on grounds different than that of a particular utility. Granting MEC's Motion at this stage of the proceeding would deprive MUI of that potential right. To dismiss a party with interests in a rate case arguably different from any other party to the case, but whose interests are still legitimate (as is the case with MUI) would be unjust and unreasonable.

254. In the alternative, MEC moved for a finding that MUI be considered as having substantially like interests and positions of NSP and that it be limited in its participation herein as a result. Specifically, MEC requested that either (a) MUI be required to make a showing that NSP has inadequately represented shareholders in this case, or (b) MUI not be allowed to submit

briefs in this case. As a further alternative, if MUI were to be allowed to submit briefs, MEC requests that the briefs not be considered apart from NSP's briefs on the issues. Since the briefing period is over, and MUI submitted no briefs, the partial remedy sought by MEC has been mooted.

MEC argues that since Minn. Rule 7830.2400 allows for the limiting of an intervenor's opportunity for cross-examination and arguing motions and objections if the intervenor has substantially like interests and positions as another party in the proceeding, that the limitation provisions of that rule should be extended to limit MUI's ability for further participation in this case (specifically, to limit its ability to brief issues). There is no authority in the cited rule for limiting the participation of parties outside the conduct of hearings. In addition, since this is a contested case proceeding under the Administrative Procedure Act, the Rules of the Office of Administrative Hearings supersede any procedural rules of an agency for which the Office is conducting that contested case proceeding. While the Administrative Law Judge is empowered to limit MUI's briefing opportunities, as well as its participation in the hearing, those situations never ripened because MUI took no active part in the proceedings and did not file briefs.

255. Minnesota Energy Comsumers' Motion to Withdraw the Intervenor's Status of the Minnesota Utility Investors is DENIED for the reasons outlined in the above Findings.

ADJUSTMENTS TO RATE BASE AND INCOME STATEMENT, REVENUE REQUIREMENT SUMMARY

256. NSP's proposed final rate base (unadjusted for Cash Working Capital) is $2,228,380,000. As shown in the table below, the Administrative Law Judge has accepted the Cash Working Capital Adjustment of $1,100,000 proffered by the Department of Public Service, rather than that of NSP or the OAG, in calculating NSP's average rate base for the test year. Based upon the above Findings, NSP's rate base should be adjusted downward by $4,771,000, as follows:

Name	Adjustment
Gain on Land Sold - Chippewa Flowage	($3,426,000)
Disputed Unamortized Rate Case Expenses	(245,000)
Cash Working Capital - DPS	(1,100,000)
Total	($4,771,000)

257. NSP's average rate base for the test year is $2,223,609,000, as computed in the preceding Finding.

258. In its final submission, NSP proposes an amount of $180,998,000 in income to be applied toward its revenue requirement. This figure is the sum of net operating income of $171,934,000 and an Allowance for Funds Used During Construction (AFUDC) of $9,064,000. It is appropriate to include AFUDC in that amount in test year income. NSP's proposed test year income should be increased by another $4,529,000, as follows (figures are net after taxes):

Name	Increase
Pathfinder	$1,441,000
Unbilled Revenues	870,000
Gain on Land Sold - Chippewa Flowage	1,371,000
Economic Development	257,000
Co-Generation Litigation (RICO)	182,000
Miscellaneous and Social-Meeting Expenses	343,000
Marketing Programs	65,000

Total	$4,529,000

As a consequence, NSP's test year income is $185,527,000.

259. As a result of the preceding Findings regarding cost of capital, rate base and test year income, the revenue deficiency of Northern States Power Company for the test year is $59,634,000, calculated as follows:

Rate Base	$2,223,609,000
Overall Rate of Return (Including 11.9 % Cost of Equity)	9.94 %
Required Operating Income (Rate Base x 9.94%)	$221,027,000
Test Year Income	$185,527,000
Income Deficiency	$35,500,000
Gross Revenue Conversion Factor	1.679825
Gross Revenue Deficiency	$59,634,000

260. NSP filed originally for a general rate increase of $98,198,000, or 8.1 percent overall. It is currently collecting an Interim Rate increase annualized at $71,904,000, or 5.94 percent. In its final submission in this matter, NSP requested a general rate increase of $83,387,000, or 6.88 percent. The gross revenue deficiency of $59,634,000 found in this Report represents a 4.9 percent general overall rate increase for NSP.

CONCEPTS TO GOVERN

261. It is the intention of the Administrative Law Judge that the concepts set forth in the Findings herein should govern the mathematical and computational aspects of the Findings and Conclusions. Any mathematical or computational errors are unintentional and should be corrected to conform to the concepts expressed in the Findings and Conclusions.

PART II - RATE DESIGN ISSUES

262. Due to the extended scope of this proceeding, the need to afford the parties an adequate period for filing exceptions and the time within which the Commission must issue its final Order, the Findings of Fact, Conclusions and Recommendations of the Administrative Law Judge will be issued in two parts. This Part I includes all issues other than those involving rate design. Part II will consider all remaining issues and will include a recommended Order.

Based upon the foregoing Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this hearing pursuant to Minn. Stat. Ch. 216B and 14.57-14.62 and Minn. Rules Part 1400.5100-.8300.

2. Any of the above Findings of Fact more properly considered Conclusions of Law are hereby adopted as such.

3. The Public Utilities Commission (PUC) gave proper notice of the hearing in this matter, has fulfilled all relevant, substantive and procedural requirements of law or rule and has the authority to take the action proposed.

4. The quantum of proof necessary to establish the facts supporting the reasonableness of proposed rate changes is proof by a preponderance of the evidence.

5. The proper test year for use in this proceeding is the twelve-month period between January 1, 1991 and December 31, 1991.

6. It is appropriate to treat the Company's test year figures based on historic data adjusted for known and measurable changes as evidence corroborating the reasonableness of NSP's forecasted test year.

6. The appropriate capital structure for use in this proceeding is 41.98 percent long-term debt, 0.42 percent short-term debt, 9.85 percent preferred stock and 47.75 percent common equity.

7. The cost of long-term debt of the Company for use in this proceeding is 8.65 percent.

8. The cost of short-term debt to be used in determining the Company's cost of capital is 7.78 percent.

9. The Company's cost of preferred stock to be used in determining its cost of capital is 6.13 percent.

10. The appropriate dividend yield component in cost of equity for the Company during the test year is 7.1 percent.

11. The appropriate growth rate component in the Company's cost of equity for the test year is 4.8 percent.

12. The appropriate cost of common equity for NSP in this proceeding is 11.9 percent.

13. The appropriate overall rate of return to be allowed the Company in this proceeding is 9.94 percent.

14. It is appropriate to reject the Company's proposal for ratepayers to reimburse expenses associated with decommissioning of NSP's Pathfinder Atomic Power Plant at Sioux Falls, South

Dakota.

15. It is appropriate for Minnesota ratepayers to share a fair proportion of NSP's profit in the sale of its Chippewa Flowage land near

Hayward, Wisconsin. An adjustment during the test year to reduce NSP's rate base by $3,426,000 and increase its net operating income by $1,371,000 would reflect the appropriate treatment during the test year. It is appropirate to order NSP to apply to the Federal Energy Regulatory Commission (FERC) for appropriate amendment of the Interchange Agreement between NSP and NSP-W.

16. It is appropriate to reject MEC's recommended normalizing adjustment to NSP's budget forecast, which would adjust operating expenses downward according to the Consumer Price Index (CPI).

17. It is appropriate to reject North Star's recommended normalizing adjustment to NSP's test year budget, which would adjust expenses downward in accordance with the estimates of utility O & M expense increases published by Data Resources, Inc. (DRI).

18. It is appropriate to require the Company, prior to the filing of its next general rate case, to make additional information available to the PUC and Intervenors at the time of that filing, as suggested by the DPS.

19. It is appropriate to adopt the proposal of the OAG for adjustment of unbilled revenues during the test year. It is inappropriate to adopt the proposal of the Office of Attorney General for recovery of accumulated unbilled revenues prior to the test year.

20. It is appropriate to reject adjustments proposed by MEC and OAG herein relating to changes implementing recommendations in the Company's TRANSCO Study.

21. NSP's proposal to amortize the cost of the replacement rotor at the Allen S. King Generating Plant, and that the unamortized balance be included in rate base, is reasonable and the Company's proposal for treatment of those funds is appropriate.

22. It is appropriate to reject NSP's proposal to recover $431,170 in test year expenses for economic development. New legislation (Minn. Stat. 216B.16, subd. 13) regarding economic development does not negate a utility's burden to show a connection between economic development programs and the provision of electric services.

23. It is appropriate to require NSP's Advantage Service to properly compensate NSP's electric operations for the use of

NSP's mailing lists, billing system and Customer Business Office personnel so that costs will be properly accounted for in future rate filings.

24. It is appropriate to order NSP to provide notice (through a billing insert or initial customer contact) to customers of the option to be dropped from mailing lists provided to entities outside NSP.

25. It is appropriate to adjust the October 31, 1990 plant balances in the Company's Functional Plant in Service (FPIS) system by $5,504,699 on a Minnesota company basis.

26. It is appropriate to remove Information Services chargebacks from test year capital expenditures, resulting in a net decrease to the rate base of $1,324,000.

27. It is appropriate to remove purchasing costs from test year capital expenditures, resulting in a net reduction to rate base of $1,649,000.

28. It is appropriate to incorporate depreciation rates approved by the Commission in Docket E-002/B-91-300 into final rates in this proceeding. The Company's newly-filed rates reduce its overall jurisdictional revenue requirements by approximately $4.8 million, but if the Commission does not approve NSP's proposal, then test year depreciation expense should be recalculated to incorporate the approved rates.

29. The Company's proposal to collect $1,465,000 during the test year for nuclear fuel which will be unburned at the end of the lives of its currently-operating nuclear power units is reasonable, appropriate and consistent with the Commission's ruling in Docket E-002/D-90-184.

30. It is appropriate to use the Conservation Improvement Program (CIP) test year expense level set by the Commissioner of the Department of Public Service in her final decision regarding NSP's CIP program on August 13, 1991 as the basis for setting test year CIP rate base amd expense levels.

31. It is appropriate to increase test year rate base by a net amount of $2,166,000, including a $931,000 reduction to remove unamortized CIP expenditures which were part of the original filing, in order to apply properly to rate base the incentive mechanism approved by the Commission to the CIP test year budget approved by the Commissioner of the Department of Public Service.

32. It is appropriate to apply NSP's approved CIP financial incentive in determining the Company's final revenue requirement. Application of the incentive mechanism to NSP's approved 1991 CIP expenditures ($16,509,671) results in a final revenue requirement for CIP expenditures of $6,647,948.

33. It is appropriate to reject the proposal of Minnesotans for an Energy Efficient Economy to deny this rate increase request in its entirety unless the Commission orders NSP to aply a societal cost test to its CIP programs and to reduce demand for electrical energy in its service territory by at least 2 percent per year, and also orders implementation of ME3's proposed Demand-Side Demonstration Initiative.

34. It is appropriate for NSP to recover previously-disallowed conservation costs of approximately $1.2 million and pre-test year expenses of $2,993,282 relating to other pre-test year conversation costs by aggregating the total amount of $4,235,863 into the Company's "Tracker" account and recovering the Tracker balance from the Interim Rate refund, if any, ordered in this case. To the extent that the Interim Rate refund is too small or if there is no Interim Rate refund, it is appropriate to amortize these expenses over a two-year period for recovery through base rates.

35. It is appropriate to grant the Company's proposed adjustment reducing revenue requirements by approximately $1.1 million for 1991 Nuclear Regulatory Commission (NRC) fees.

36. It is appropriate to remove an additional $245,000 from NSP's test year rate base to allow recovery of rate case expenses during the test year. The $245,000 is in addition to a $372,000 adjustment NSP has already agreed to.

37. It is appropriate for NSP to recover litigation expenses related to Docket E-002/CG-88-491 (Biosyn) over a two-year period.

38. It is appropriate to dismiss without prejudice NSP's request for recovery during the test year of litigation expenses generated by its defense in an antitrust and RICO action filed by Biosyn and others.

39. It is inappropriate to include revenues from the transportation of coal from the University of Minnesota in test year revenues.

40. It is inappropriate to recognize revenues from the exchange of nuclear fuel and fuel-related services not needed for NSP's Monticello and Prairie Island nuclear plants in test year revenues.

41. It is appropriate to exclude $321,626 in miscellaneous and meeting expenses from NSP's test year operating expense budget.

42. It is appropriate to exclude $261,157 of proposed social expenses from test year expenses.

43. It is appropriate to exclude from test year expenses those

expenses associated with NSP's electric sales programs for electric cooking, snow-melting and infrared heating.

44. It is appropriate to adopt for purposes of this filing the requested budget for the Company's Load Management Promotion program, and to include that program in CIP.

45. It is appropriate for the Commission to adopt NSP's test year sales forecast.

46. It is appropriate to reject MEC's proposal to reduce plant inventory by $10 million for alleged inventory reduction at the Company's Maple Grove facility.

47. It is appropriate to include costs in the test year related to the purchase of power by NSP from Cyprus Minerals, unless, prior to the issuance of its final order in this case, the PUC disapproves of the contract pending before it between NSP and Cyprus.

48. It is inappropriate to recognize test year revenues for any period longer than two months in connection with the provision of wheeling services to WPPI by NSP.

49. It is inappropriate to adjust test year revenues for wheeling revenues received under a generic tariff for the provision of services the Company filed with the FERC.

50. It is appropriate to reject MEC's proposal to modify NSP's proposed investment strategy for external tax-qualified nuclear decommissioning funds.

51. It is appropriate to allow NSP to adjust its rate increase request by $5,672,832, as filed for in its Motion to Update Filing of May 13, 1991.

52. It is appropriate to reduce NSP's revenue requirements in this proceeding by $3,257,900 pursuant to the Stipulation on Deferred Expenses

executed by NSP, DPS, OAG and MEC. Acceptance of that Stipulation into the record does not preclude the establishment from other portions of the record of any further adjustments for deferred expenses.

53. It is inappropriate to adopt the arguments presented in prefiled testimony by MEC to deny recovery of NSP's incentive compensation costs totalling $14,734,000 in their entirety.

54. It is appropriate to allow NSP to place into the record its admission that its incentive compensation for the test year was overstated by $1,973,701, and to reduce the Company's revenue requirement by that amount as a result.

55. It is appropriate to deny MEC's Motion for Sanctions regarding incentive compensation in this proceeding, which, if granted, would also deny revocery of all of NSP's incentive compensation costs.

56. It is not appropriate to remove NSP's Red Wing and Wilmarth plants from the test year rate base in this proceeding.

57. It is appropriate for the Commission to order an investigation, pursuant to Minn. Stat. 216B.17, into the question of whether NSP's non-regulated refuse derived fuel (RDF) business has been improperly subsidized by NSP's regulated rate payers.

58. It is appropriate to deny OAG's proposal to impute $1,035,000 in cost savings related to the Red Wing and Wilmarth plants.

59. No adjustment should be made to NSP's test year revenue requirement for excessive capacity cost payments to United Power Association in connection with MSW/RDF operations in Elk River.

60. It is appropriate to deny MEC's Motion to Dismiss Minnesota Utility Investors (MUI) as a party to this proceeding.

61. It is appropropirate to include $9,064,000 as Allowance for Funds Used During Construction in test year income.

62. It is appropriate to set NSP's average rate base for the test year at $2,223,609,000.

63. It is appropriate to set NSP's test year income at $185,527,000.

64. The appropriate revenue deficiency for Northern States Power Company during the test year is $59,634,000.

Dated this   day of September, 1991.

RICHARD C. LUIS
Administrative Law Judge

Reported: Harold Reiner & Associates
Transcripts prepared.